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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	)	DOCKET NO. E-01933A-05-0650
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 ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. E-01933A-07-____

TUCSON ELECTRIC POWER COMPANY

APPLICATION

TESTIMONY AND EXHIBITS

VOLUME 3 OF 4

July 2, 2007

Direct Testimony of D. Bentley Erdwurm

BEFORE THE ARIZONA CORPORATION COMMISSION

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Direct Testimony of

D. Bentley Erdwurm

on Behalf of

Tucson Electric Power Company

July 2, 2007

TABLE OF CONTENTS

I. Introduction 1

II. Jurisdictional Allocation 4

III. Summary of the Three Rate Setting Methodologies 7

- A. Power Supply in the Cost-of-Service Methodology and the Proposed PPFAC 8
- B. Power Supply in the Market Methodology 11
- C. Power Supply in the Hybrid Methodology and the Proposed PPFAC 11

IV. Weather Normalization Adjustment 12

V. Customer Annualization Adjustment 16

VI. Class Cost of Service Study 18

VII. Rate Design 25

- A. Unbundling Methodology 26
- B. Transmission – OATT Rate 28
- C. Time-of-Use Rates for Residential and General Service (< 200kW) Customers 30
- D. Time-of-Use - Large General Service and Large Light and Power 33
- E. Time-of-Use and Residential Guarantee Rates 33
- F. Time-of-Use Rates - Determination of Time Periods 34
- G. Residential/Small Commercial Inverted Block (Tiered) Rates 35
- H. Customer Charges Changes 36
- I. Lifeline Discount for Low-Income Customers 36
- J. Proposed Revenue Changes by Class 37

VI. Service and Late Fee Adjustments 37

Exhibits:

Exhibit DBE-1	Termination Costs Regulatory Asset Charge – Rider 4
Exhibit DBE-2	Proposed Market Tariffs
Exhibit DBE-3	Proposed Cost-of-Service Tariffs
Exhibit DBE-4	Proposed Hybrid Tariffs
Exhibit DBE-5	Transmission Cost Adjustment Charge – Rider 5

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is D. Bentley Erdwurm. My business address is One South Church Avenue, Tucson, Arizona, 85701.

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

A. I am employed by TEP as a Lead Analyst in the Rates and Revenue Requirements department. In this role I prepare cost of service studies and rate design proposals.

Q. Please describe your education and experience.

A. I earned my Master of Science in Economics from Texas A&M University, and my Bachelor of Arts in Economics from the University of Dallas. I have 25 years of utility experience in the areas of cost allocation and rate design, forecasting, valuation and fair market value determination, and utility mergers and acquisitions. I have testified before state regulators in Arizona, Texas and Alabama on these issues. I testified on behalf of TEP in general rates cases during the 1990's on issues related to cost allocation, rate design and unbundling to facilitate direct access.

Q. What is the purpose of your Direct Testimony?

A. I am sponsoring, and my Direct Testimony supports, the Company's jurisdictional allocation study, cost allocation to retail classes of service (i.e., the class cost of service study ("CCOSS"), rate design and the proof of revenue analysis. These analyses are presented for each of three (3) methodologies: (i) the "Market Methodology", (ii) the "Cost-of-Service Methodology", and (iii) the "Hybrid Methodology". I am sponsoring Schedules G, G-Hybrid, G-Market, H, H-Hybrid and H-Market, which summarize the

CCOSS, rate design analyses and proofs of revenue for this filing. I also sponsor the Weather Normalization, Year-End Customer Annualization, and Service and Late Fee pro-forma adjustments shown in Schedule C-2. Additionally, my Direct Testimony supports the use of the four coincident peak method ("4-CP") to allocate capacity-related production costs in the jurisdictional allocation study, the Average and Peaks Method to allocate these costs in the CCOSS, Time-of-Use ("TOU") proposals, and recovery for proposed Demand-Side Management ("DSM") programs.

I am also sponsoring the tariffs for each of the three Methodologies.

Q. **Please summarize your recommendations.**

A. I recommend that the Arizona Corporation Commission ("Commission"):

1. Accept the Company's jurisdictional allocation proposal which assigns test-year adjusted costs to the state and federal jurisdictions;
2. Adopt the Market Methodology or, in the alternative, either of the Cost-of-Service or Hybrid Methodologies;
3. Accept the Company's weather normalization adjustment;
4. Accept the Company's customer annualization adjustment;
5. Accept the Company's CCOSS methodology;
6. Accept the Company's rate design proposals:
   - A. Accept TEP's unbundling methodology;
   - B. Affirm the Company's use of the Open Access Transmission Tariff ("OATT") rate for transmission and ancillary services;
   - C. Accept the Company's plan for expanding Residential and General Service TOU service. For Residential customers (Pricing Plan R-01) and Small General Service customers (Pricing Plan GS-10), place new customers, customers moving from one location to another, and customers

with meter change-outs on the Company's proposed TOU rates (R-70N and GS-76N), and freeze existing non-TOU rates (i.e., close to new subscription but retain for certain existing customers);

D. Place all Large General Service customers (Pricing Plan GS-13) and Large Light and Power customers (Pricing Plan LLP-14) on proposed TOU rates (Pricing Plans GS-85N and LLP-90N);

E. Replace current Guarantee Home TOU rates (Pricing Plans R-201B and R-201C) with newly designed Pricing Plans R-201BN and R-201CN. Pricing Plan R-201A will be frozen (i.e., closed to new subscription but retained for certain existing customers);

F. Accept the TOU periods for the proposed TOU rates;

G. Accept the Company's proposed inverted-block (tiered) structure for Residential customers and for General Service customers in plans generally applicable to customers with loads less than 200 kW. The first tier structure is sometimes referred to as a "Lifeline Rate Block";

H. Accept the Company's proposed cost-based customer charges, subject to a $3.50 per month cap on increases for Residential and General Service customers;

I. Accept the Company's proposed revenue changes by class; and,

7. Accept the Company's service and late fee adjustment.

Q. How does the Commission's choice among the three Methodologies affect your rate design proposals?

A. The choice does not affect rate design proposals; the proposals apply to all three Methodologies. The rate design proposals are independent of the Methodologies, because the underlying goals remain unchanged. These goals include shifting load away from critical peak periods, cost-based rates (except for the substitution of the Market

Generation Credit ("MGC") for the unbundled generation rate in the Market Methodology), and establishment of an inverted block rate ("Lifeline Block Rate") allowing small customers to buy a small "necessities-only" block of energy at a reduced rate. These goals help defer capacity additions, promote the wise use of energy resources, and reward small customers who can control usage.

II. JURISDICTIONAL ALLOCATION.

Q. Please describe the jurisdictional allocation process.

A. Under the Commission's current ratemaking treatment, the jurisdictional allocation methodology is employed to assign costs to state or federal jurisdictions. The Federal Energy Regulatory Commission ("FERC") regulates TEP's sales to wholesale customers, while the Commission regulates retail sales. Since the advent of direct access, transmission and related ancillary services have been separated from the operation of the local distribution/delivery company (TEP in a direct access mode). For this reason, transmission-related items have been removed from the retail jurisdiction in the embedded cost-of-service studies, and replaced with a transmission expense based on the FERC-approved OATT. Transmission and related ancillary services is treated as if supplied and billed by a separate entity, which is consistent with the current functioning of the transmission operation. Transmission rate base and expenses have been moved to the FERC jurisdiction.

For ratemaking purposes, rate base and expenses are separated by assigning and allocating elements of these costs to each jurisdiction. The costs are allocated by using a demand or energy allocator, based on precedent supporting a simple view of cost causation.

Q. What allocation factor is used to allocate generation-related demand and expense?

A. TEP used the 4CP in the jurisdictional allocation. FERC has accepted this method for TEP. For jurisdictional allocation, the 4CP approach is appropriate for a system most likely to peak in the months of June through September.

Q. Please explain the 4CP allocation.

A. Coincident peak demand determines the maximum capacity of the system. It is the demand of each jurisdiction at system peak that determines each jurisdiction's use of that capacity. However, the timing of the system peak cannot be predicted with certainty. The system is designed to meet peak demands in the months of June, July, August and September, the months when the annual peak almost certainly occurs. The allocation factor for generation capacity is calculated using each jurisdiction's contribution to system peak at the time of the June, July, August and September peaks.

Q. Has the Commission previously approved this approach for TEP?

A. Yes. The 4CP approach, approved by FERC, was accepted by this Commission in TEP's last general rate case for purposes of jurisdictional allocation.

Q. What is the basis for saying that the TEP system is most likely to peak in June through September?

A. For summers between 1980 and 2006, the annual retail peak demand has occurred four times in June, seven times in July, fourteen times in August and twice in September. Furthermore, the retail peak has always occurred in the summer months of June, July, August or September. This is the basis for TEP's conclusion that the peak will occur during these months.

Q. How was the 4CP allocation factor for the Commission jurisdiction determined?

A. The allocation factor of 94.53% is based upon the average of the measured four summer monthly peaks during the summer of 2006. The computation was based on the following factors:

1. The retail component for allocation purposes is computed by dividing the retail peak by the total system load. The result in this case is a 94.53% allocation.
2. Total average, hourly, peak system firm load for the four summer months of 2006 was 2,335 MW.
3. The average of the four summer months' retail peaks was 2,207 MW.
4. The average FERC jurisdictional load is equal to the difference between the average system peak and the average retail peak, which is 128 MW. This load is comprised of a 100 MW sale to Salt River Project, an average sale of 26 MW sale to the Navajo Tribal Utility Authority, and a 2 MW sale to the Tohono O'Odham Authority.

Q. What allocation factor is used to allocate generation-related energy rate base and expense?

A. Energy-related expense is allocated using pro forma adjusted test-year firm energy deliveries to the retail jurisdiction and test-year wholesale deliveries, both adjusted for losses. The computation was based on the following factors:

1. Pro forma adjusted retail sales adjusted for losses were 10,231 GWh.
2. Wholesale sales adjusted for losses were 1,192 GWh for the period ending December 31, 2006.
3. Dividing the retail sales by the wholesale sales results in 89.56% - the percentage that is allocated to ACC jurisdiction.
4. The remainder is allocated to FERC jurisdiction.

III. SUMMARY OF THE THREE RATE SETTING METHODOLOGIES.

Q. **Please describe the Company's proposed Methodologies for setting rates, as well as their similarities and differences from the standpoint of the Company's cost allocation and rate design proposals in this proceeding.**

A. An overview of the three Methodologies, along with related policy objectives and the Company's rationale for presenting the three Methodologies is contained in Mr. James Pignatelli's Direct Testimony. Mr. David Hutchens' Direct Testimony provides a detailed analysis of power supply (generation) scenarios under the Methodologies. My Direct Testimony focuses on the rates that customers will see under the Methodologies.

Under the Market Methodology, the Market Generation Credit ("MGC"), established in the unbundled rates from the 1999 Settlement Agreement, serves as the generation component associated with fuel and purchased power recovery (F&PP Generation Component). With the expiration by 2009 of both the Fixed and Floating Competitive Transition Charges ("CTC"), the F&PP Generation Component of a customer's bill would fluctuate with the market conditions reflected by the monthly MGC calculation. The Market Methodology is the logical consequence of the well-considered, well-debated unbundled rate design that was adopted by this Commission when it approved the 1999 Settlement Agreement in Decision No. 62103.

Under the Cost-of-Service Methodology, the Company is seeking to recover a $788 million Termination Costs Regulatory Asset ("TCRA") that is discussed in the Direct Testimony of Mr. Kentton Grant. The costs associated with the $788 million TCRA are recovered volumetrically through a Termination Costs Regulatory Asset Charge ("TCRAC"); these costs are not included in base rates. The TCRAC does not vary by class; for calendar 2009 TCRAC will be $0.0126 per kWh applicable to all retail

customers, except current contracts for contract customers. The TCRAC will be updated on an annual basis. TEP requests that the Commission approve recovery of the TCRAC from all retail customers, including new contract customers, and current contract customers after the expiration of the current contract. The Company's proposed Termination Costs Regulatory Asset Recovery – Rider 4 is attached as Exhibit 1 to my Direct Testimony.

The Company also seeks recovery of a $47 million Implementation Costs Regulatory Asset ("ICRA") under the Cost-of-Service and Hybrid Methodologies. In the Market Methodology, the Company is requesting recovery of a $14.2 million ICRA, as discussed in the Direct Testimony of Ms. Karen Kissinger. The costs associated with the $47 million ICRA are allocated to classes on the basis of energy, to match the method previously approved for system benefits. The $47 million ICRA is included in rate base.

Chief differences in the three Methodologies include the regulatory asset recovery and the treatment of power supply cost. Under all three Methodologies, specific components for local generation, transmission, ancillary services, distribution/delivery, customer, customer-metering, customer-meter reading, customer-billing, and system benefits are approved by the Commission.

A. <u>Power Supply in the Cost-of-Service Methodology and the Proposed PPFAC</u>.

Q. Please discuss how power supply is handled in the Cost-of-Service Methodology.

A. The Cost-of-Service Methodology bases generation on average embedded cost, subject to adjustment through the Purchased Power and Fuel Adjustment Clause ("PPFAC"), as described in Mr. Hutchens' Direct Testimony. The cost-of-service approach was standard for TEP before the implementation of the unbundled rates approved in the 1999

Settlement Agreement. The ramifications of implementing the Cost-of-Service Methodology are discussed in Mr. Pignatelli's Direct Testimony. Under the Cost-of-Service Methodology, no plant is designated as a wholesale asset; however a Market-Based Demand Charge is being used as the non-fuel cost basis for the Springerville Unit No. 1 and Luna generating facilities, as Mr. Hutchens sets forth in his Direct Testimony.

Under the Cost-of-Service Methodology, generation costs not reconcilable through the PPFAC (i.e., capacity-related generation assets upon which TEP earns a return) will be included in base rates and recovered through a Base Generation Capacity Component. These generation costs are allocated on the basis of average and peaks. The justification for allocating capacity-related generation costs on average and peaks is discussed later in my Direct Testimony. A second generation component will recover the Base Cost of Fuel and Purchased Power ("Base Cost of Fuel and Purchased Power Component") through base rates as well. The fuel, purchased power, and other items in this component are allocated in the cost-of-service study on both Weighted Energy and Average and Peaks. Mr. Hutchens also discusses this Base Cost of Fuel and Purchased Power in his Direct Testimony. Changes in fuel and purchased power costs in the future, along with other items detailed by Mr. Hutchens, will be reflected in the PPFAC. The Company proposes that the Base Cost of Fuel and Purchased Power Component be adjusted to reflect early 2009 levels so that no initial adjustment through the PPFAC is necessary when rates go into effect.

Q. **Is the Company requesting to adjust the Base Cost of Fuel and Purchased Power Component for anticipated market conditions when rates are expected to go into effect?**

A. Yes. This is discussed and supported in the Direct Testimony of Mr. Hutchens. A key advantage of this approach is simplicity. Customers do not think in terms of test years.

They focus on when rates go into effect. Under TEP's proposal, the Base Cost of Fuel and Purchased Power is trued-up to levels prevailing at the time of the implementation of rates in late 2008 or early 2009. Changes in PPFAC-reconcilable costs are easier to track when the initial PPFAC is set to zero. The customer knows that any recovery or refund through the PPFAC is attributable to changes in the cost of fuel and purchased power (the PPFAC-reconcilable costs) occurring after the date of rate implementation. No PPFAC adjustment is necessary at the time of rate implementation because the component is set at expected cost.

From a rate design and cost allocation perspective, the Company notes that the initial adjustment to the Base Cost of Fuel and Purchased Power is a one-of-a kind adjustment, occurring only once, upon implementation of the new rates no later than the beginning of 2009. While the request may at first blush appear to push the boundaries of future test years, consider that the pre-2009 adjustment is non-recurring, and allows any change in PPFAC-eligible costs through pre-2009 to be allocated to customer classes using the Weighted Energy allocator and the Average and Peaks allocator as in the class cost of service study. The PPFAC recovers eligible costs on a volumetric basis, making no distinction for load factor differences. As such, higher load factor customers pay a slightly larger share of PPFAC-eligible cost increases under the volumetric PPFAC mechanism than they would under the Average and Peaks approach used in the class cost of service study. Symmetrically, these same high load factor customers under the PPFAC would receive a slightly larger share of any credit attributable to PPFAC-eligible cost decreases. Volumetric recovery through the PPFAC, while not matching TEP's proposed class cost allocation approach to cost recovery, is a reasonable mechanism, given that a large percentage (85%) of the test-year's Base Cost of Fuel and Purchased Power is allocated on a Weighted Energy basis, and Average and Peaks applies to only the remaining 15% of costs. The difference in cost assignment under PPFAC and under

the CCOSS is relatively small. When and if PPFAC-eligible costs increase subsequent to the proposed single adjustment to the Base Cost of Fuel and Purchased Power prior to 2009, the Commission may actually prefer the PPFAC mechanism for recovering such eligible cost changes because it provides a slightly bigger incentive to conserve. Under the proposed PPFAC, high load factor customers (large energy use relative to demand) pay the same unit cost as other customers.

B. <u>Power Supply in the Market Methodology</u>.

Q. **Please discuss how power supply is handled in the Market Methodology, and compare that approach to the Cost-of-Service Methodology.**

A. The Market Methodology bases generation on the MGC, as currently found in TEP's unbundled direct access tariffs. TEP's current Fixed CTC and Floating CTC will expire no later than December 31, 2008. Under TEP's current rates, the Floating CTC adjusts downward (upward) when the MGC adjusts upward (downward). The net effect under current rates is to hold the total generation component constant. When the Fixed CTC and Floating CTC end, the generation component will, as expected, fluctuate under the Market Methodology. The MGC in the Market Methodology replaces the Base Generation Capacity Component, the Base Cost of Fuel and Purchased Power Component, and the PPFAC in the Cost-of-Service Methodology.

C. <u>Power Supply in the Hybrid Methodology and the Proposed PPFAC.</u>

Q. **Please discuss how power supply is handled in the Hybrid Methodology, and compare to the approach in the Cost-of-Service Methodology.**

A. The Hybrid Methodology is similar to the Cost-of-Service Methodology. In the event that the Commission chooses this methodology, the Company requests that all generation

be recovered through base rates and the PPFAC mechanism except costs for the Navajo and Four Corners Generating Stations (which are designated as wholesale assets). Under the Hybrid Methodology, Navajo and Four Corners are designated as wholesale assets; and as in the Cost-of-Service case, a Market-Based Demand Charge is being used as the non-fuel cost basis for Springerville Unit No. 1 and Luna Energy Facility costs.

IV. WEATHER NORMALIZATION ADJUSTMENT.

Q. What is the purpose of a weather normalization adjustment?

A. A weather normalization adjustment is performed to represent test year sales, revenues and costs under normal weather conditions. Energy consumption for several TEP customer classes is weather sensitive. For instance, a significant portion of energy usage in the summer comes from air conditioning. Some summers, however, are warmer than normal and the Company receives more revenues and incurs more costs as a result. This is because it takes more energy for customers to cool their homes and businesses when the average temperature is higher during the summer months. But a cooler than normal summer can result in the Company receiving less revenues and incurring less costs, because less energy is needed to cool homes and businesses. Hence, 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 and incur as costs during a particular year. In other words, the weather normalization adjustment quantifies the change in kWh sales, revenue and costs that would have occurred if the weather in the test year had been typical. An analogous concept applies in the winter, where customers will use a significant percentage of energy to heat their homes and businesses.

Q. How is annual usage normalized based on the weather in order to make this adjustment?

A. The industry uses 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. Electric heating requirements are small when average daily temperatures are greater than 65 degrees Fahrenheit, and cooling requirements are small when the average daily temperatures are less than 75 degrees Fahrenheit. In other words, customers will generally have no need for heating when temperatures are at or above 65 degrees Fahrenheit, and customers will have no need for cooling when temperatures are at or below 75 degrees Fahrenheit. Therefore, a HDD is measured by subtracting 65 degrees from the average of the maximum and minimum temperature for that day. 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 are set to zero.

Actual CDDs and HDDs for the TEP service area are then compared to what the typical or normal weather has been in those areas. This is done for each month. The normal weather for each calendar month is then determined as the average monthly HDDs and CDDs that have been recorded over the last ten years.

Q. Please provide an overview of weather normalization.

A. To quantify how much a summer month's electricity usage changes in response to weather's deviating from normal, the statistical technique of linear regression analysis was used. The analysis focused on the consumption behavior of a single average customer – specifically on this customer's use-per-customer ("UPC"). Regression models estimate how much electricity UPC changed in response to a change of one CDD. Regression analysis is used to estimate how much a dependent variable "y" (*e.g.*, UPC)

changes in response to some change in an independent variable "x" (*e.g.*, CDD). This estimate, the slope coefficient, represents the change in "y" divided by the change in "x."

When regression is used for weather adjustments, one multiplies the slope coefficient (change in UPC/change in CDD) by the deviation from normal weather (*i.e.*, the difference in normal and actual CDD [CDDN – CDDA]). The result of this calculation is the weather adjustment in kWh per customer. To obtain the total weather adjustment, the weather adjustment per customer is simply multiplied by number of customers.

Similar adjustments are calculated for each month (with HDD substituted where appropriate) and for each applicable class of service.

Q. Please describe your weather normalization calculations in more detail.

A. I performed weather normalization calculations for the residential customer class separately from general customers. For the residential class, I used historical weather and UPC data to calculate the weather adjustment. For cooler months with heating requirements, I calculated an incremental UPC per HDD above base usage. To put it another way, I calculated the amount of energy a residential customer used to heat his or her home per degree per day. Likewise, for warmer months with cooling requirements, I calculated an incremental UPC per CDD above base usage, or the amount of energy a residential customer used to cool his or her home per degree per day.

For non-residential classes, I performed similar adjustments, but only for the cooling requirements. This is because none of the non-residential weather adjustments are based on heating requirements (typically driven by HDD's). Non-residential heating load changes little in response to the HDD variation experienced in the TEP's service territory.

In fact, given the mild winters, it is not unusual to find commercial and industrial customers using air conditioning during the "coldest" winter months.

The base load month (fewest historic HDD) for heating requirements is July or August, and the base load month for cooling requirements (fewest historic CDD) is December, January, or February. To recognize that customers typically do not use heating equipment anywhere in Arizona in the summer, I limited my HDD weather adjustment calculations to the months of January through April, November and December of the test year. Regression analyses resulted in a heating factor, or monthly heat load per HDD. The monthly heating factor was multiplied by the respective month's deviation from normal HDD to develop the composite weather adjustment per customer, with this result subsequently multiplied by the number of customers to obtain the total weather adjustment. The CDD weather adjustment calculation was similarly calculated.

Q. What did your calculations show?

A. Overall, weather was less extreme than normal (*i.e.,* less cold in the winter and/or less warm in the summer.) Therefore, sales were slightly lower than normal resulting in a "positive" adjustment to sales volumes (kWh) and to operating income (revenue and costs). As described below, this positive weather adjustment has the end result of *lowering* the revenue requirement, thus benefiting customers.

Q. Did you weather-normalize all rate classes?

A. No, I weather-normalized only those rate classes where sales are weather sensitive. Sales to the Large Light and Power, Irrigation, Public Authority and Lighting classes were not weather sensitive and consequently were not weather normalized.

Q. What was the effect of weather adjustments on test year sales volumes, operating income, and the revenue requirement?

A. Because sales were slightly lower than normal, it is necessary to make positive adjustments to reflect a "normalized" level of sales. The net result of these weather normalization adjustments was to adjust the total actual sales volumes upward. The weather adjustment was a positive 53,849,952 kWh. The total unadjusted kWh was 9,201,419,165. The weather adjustment therefore accounts for less than 0.6 % (less than six-tenths of one percent) of sales. Incremental kWh growth associated with the weather adjustment will increase revenue and variable (as opposed to fixed) expenses. In this case, incremental net margin (the difference in revenue and variable expenses) is positive. Therefore, because the incremental net margin is positive, it will increase the total operating income and reduce the total revenue requirement. The reduction in the revenue requirement associated with the weather normalization adjustment is $7,593,726 (equals the tax conversion factor of 1.6609 times the operating income effect of $4,572,055). The effect of the weather adjustment is to reduce the amount of the rate increase relative to what it would have been absent the weather adjustment.

V. CUSTOMER ANNUALIZATION ADJUSTMENT.

Q. Please describe the customer annualization adjustment.

A. The customer annualization adjustment restates 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 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 customer differences by the normalized UPC 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 unadjusted (*i.e.*, actual) billing determinants – should result in adjusted billing determinants that will accurately reflect the bills and volumes during the time rates will be in effect. If there is a positive growth rate in the number of customers, and if the last month of the test year reflects a customer count at or close to the test year maximum and customer growth is not cyclical, then making adjustments to reflect values at test-year-end is appropriate. That was the case here and it is particularly appropriate given the anticipated growth in our service area. Under the conditions described above and existing in this case – that there is a positive growth rate in the number of customers, and that the last month of the test year reflects a customer count at or statistically close to the test year maximum – and customer growth is not cyclical the year-end adjustment technique results is the most accurate method to determine what sales will be for the time rates are in effect. 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 therefore is most effective in mitigating the rate increase TEP requests in this application.

Q. How does the customer annualization adjustment affect test-year sales, operating income, and revenue requirement?

A. As I mentioned above, positive customer annualization adjustments affect customers, kWh, and can also affect kW. This means that adjusted billing determinants will be adjusted upward. So, increasing these billing determinants increases both adjusted revenues and expenses. The customer adjustment is a positive 63,579,987 kWh. This is

less than 0.7% (less than seven-tenths of one percent) of total unadjusted kWh sales of 9,201,149,165 kWh. Because the incremental net margin is positive, it will increase the *total* operating income and reduce the *total* revenue requirement. The reduction in the revenue requirement associated with the customer annualization adjustment is $12,480,958 (equals the tax conversion factor of 1.6609 times the operating income effect of $7,514,575). The effect of the customer adjustment is to reduce the amount of the rate increase relative to what it would have been absent the customer annualization adjustment.

VI. CLASS COST OF SERVICE STUDY.

Q. What is the purpose of a CCOSS?

A. The purpose of a CCOSS is to assign each cost component to the respective classes in order to determine an appropriate total cost to serve each class. A cost component may be one of three things: (1) an individual rate base or expense account as defined in the FERC Uniform System of Accounts; (2) a portion of a single FERC account (e.g., the "coincident peak demand-related" portion of an account), or (3) some composite of accounts. An example of a single FERC account is Account 364, which is a rate base account for distribution and overhead lines (aptly named Distribution - Overhead Lines).

Q. What are the steps in designing a CCOSS?

A. There are three basic steps involved in developing a CCOSS. Those steps are: functionalization, classification, and allocation. Functionalization involves grouping cost components by purpose or function. Some examples of functions include transmission, distribution-primary lines, metering, and meter-reading. The CCOSS presented by the Company in this proceeding identifies over 20 different functions. The next step, classification, involves identifying each function as demand-related, energy-related or

customer-related. The final step, allocation, involves apportioning each cost component to the classes of service (*e.g.*, residential, commercial and industrial).

Q. Please describe how costs are classified for purposes of the CCOSS.

A. Costs classified as demand are most affected by the level of kW by class. These demand-classified costs are either coincident, meaning that they occur at the same time, or non-coincident, meaning at times that may vary. Coincident demands tend to be more correlated with cost at the production level. In other words, coincident demands address whether there is purchased power and generation capacity for TEP's entire system needs. Consequently, non-coincident demands become more correlated with cost as we move downstream though the distribution system to the end-users.

Costs classified as energy are most affected by kWh by class. The energy classification can be affected either by time-of-day (*e.g.*, on-peak, shoulder-peak, and off-peak) or non-time-differentiated. Finally, costs classified as customer are based on class customer counts – either non-weighted counts or weighted counts. Weighted counts take into account not just the number of customers but the level of costs imposed by the customers. In dealing with billing costs, for example, a residential customer may be defined as one "weighted customer" and an industrial customer that costs 20 times as much to meter would count as 20 "weighted customers."

Q. Please describe the allocation step in designing a CCOSS?

A. As I stated above, allocation involves assigning each cost component to the different classes of service, including residential, commercial and industrial. Each function has a single allocation factor that applies to all cost components in that function. The allocation factor should be based upon an equitable method that harmonizes the cost-causation with the functional cost being considered. In other words, the allocation should

be done in a way where the cost-causation for the functional cost considered is properly identified.

Q. Please describe the CCOSS model used in this proceeding.

A. The model, created in Microsoft Excel, starts with cost components by function, known as functionalized costs. The model presents functionalized and classified costs vertically (*i.e.*, in rows down the spreadsheet) and the allocation of costs to rate classes horizontally (*i.e.*, in columns across the spreadsheet). Each functionalized and classified cost is then fully allocated to the customer classes. The percentage of a given cost allocated to a specific class will depend on the function and its associated allocation factor. A cost associated with billing customers, for example, should be allocated so that it reasonably approximates the cost of billing the customers by class. As mentioned above, a weighted customer basis would be used to derive a factor that reflects both the number of customers by class and the level of costs each customer class imposes.

Q. Are there different types of allocation factors?

A. Yes. Some allocation factors used are "external" allocation factors. External allocation factors are determined independent of the magnitude of specific costs in the CCOSS. That is, the external allocation factor is developed in an analysis separate from the CCOSS. An example of an external allocation factor is the distribution substations – demand sub-transmission allocation factor, which is the factor used for the allocation of distribution substations component of distribution plant. This factor is further functionalized as demand sub-transmission and is based on non-coincident peak demands ("NCP").

Another external allocation factor – the Demand Production allocation factor - is based on the Average and Peaks Method. This method is also described in more detail below.

Q. Are there also internal allocation factors?

A. Yes, an internal allocation factor is calculated within the CCOSS model and is dependent on the cost components found therein. For example, Deferred Taxes and Tax Credits are allocated based on Total Plant in Service. Total Plant in Service is a composite of different plant categories (*e.g.*, transmission, distribution). To the extent that plant categories are allocated differently, the Total Plant in Service allocator will vary based on the level of different plant types of net plant. Total Plant in Service, like all internal allocation factors, is a weighted average of other allocation factors. The relative sizes of cost components determine the weights in the weighted average.

Q. Is there a listing of allocation factors?

A. Yes. Allocation factors are listed in Schedule G-7. As shown, some factors are "customer-related." Studies on metering, services, meter reading, customer service and billing provide the basis for the customer-related factors. Additionally, there are factors based on labor costs, throughput, or internal factors based on individual or aggregate costs.

Q. Please describe the Average and Peaks Method.

A. The Average and Peaks Method provides the basis of allocation for the largest cost component – production and transmission-related costs. This method has been approved by the Commission in previous TEP general rate cases. The Average and Peaks 4CP factor is made up of two components: an average demand component (with a percentage weight of the system load factor) and a peak demand component (with a percentage weight of one minus the system load factor). The average demand component was calculated by dividing the number of hours in the test-year into the loss-adjusted energy. The peak demand component was calculated as a combination of coincident peak demands (time of system peak) from June, July, August, and September of the test-year.

The system peak during a period of 12 consecutive months occurs with greatest likelihood in these four summer months.

Q. Does this methodology recognize differences in baseload versus other types of capacity?

A. Yes. The allocator includes the peak component to recognize that the system must have adequate capacity to satisfy demand at the time of the peak, and that classes of customers should receive some allocation of costs reflecting contribution to this peak. But the allocator also includes the average demand component to recognize that different types of capacity – baseload, intermediate and peaking capacity – are installed depending on energy use and the duration of load. Baseload capacity has a relatively high capital cost, but a relatively low running (incremental O&M and fuel) cost. Consequently, the average total cost per kWh, which is the sum of capital cost and running cost, from baseload capacity falls as the utilization of the baseload capacity increases.

Peaking capacity, on the other hand, has relatively low capital costs and relatively high running costs. As a general rule, a system with a low load factor (peak demand high relative to average demand) will have more peaking units, and a higher load factor system will have more baseload units, other things equal. Typically, higher load factor customers' energy use helps support the addition of baseload capacity. The average demand component of the production allocator reflects the impact of energy use on the mix of capacity and its cost.

Q. Does load factor also play a role in determining the basis for cost components for this average and peak method used in your CCOSS?

A. Typically, higher load factor customers' energy use helps support the addition of baseload capacity. The average demand component of the production allocator reflects the impact

of energy use on the mix of capacity and its cost. While the Company owns no generation, and purchases its requirements under contract, the average and peaks approach is still appropriate. Power suppliers are going to demand a higher average price to serve a load with high peaks and a low load factor. The average and peaks approach allocates more cost to customer groups with relatively high coincident peak and relatively low system load factor.

Q. Did your CCOSS also take into account differences between energy use from summer versus winter?

A. Given that the production allocator contains the average demand component, energy-related incremental costs such as fuel and portions of purchased power (cost items functionalized as Cost-weighted Energy) have been allocated by a cost weighted allocation factor. This factor is based on energy use by class by time of day and by season, adjusted for the average variable cost during the respective periods. Therefore, the factor reflects that consumption during the peak periods of the summer is more costly than an equal amount of consumption during the off-peak winter periods.

Q. Why should the cost weighted energy allocation factor be used to allocate fuel and purchased power costs such as fuel and purchased power if an average demand component is used in the production allocator?

A. As I explained above, energy use (load duration) affects the mix of capacity and its cost, and that higher load factor customers' energy use helps justify baseload capacity. It follows that higher load factor customers (who are paying for baseload capacity through the average demand component of the production allocator) should receive the benefit of the lower average variable costs – like lower fuel cost – (e.g., due to lower cost fuel) associated with the baseload plants. The cost-weighted energy allocator is an attempt to match energy use with plant. As a practical matter, however, the cost weighted energy

factor is almost identical to the non-weighted energy factor due to the proportion of baseload capacity on the Company's system. The addition over time of peaking facilities (relative to baseload facilities) could cause the factors to differ more markedly.

Q. Is the Company's overall allocation approach consistent with past approaches approved by the Commission?

A. Yes. Allocations for the production and the use of weighted customers for billing, metering and meter reading match the approach approved in TEP's last general rate case.

Q. What is the final objective of the CCOSS?

A. Based on allocated costs, the goal is to confirm the extent to which present and proposed rates generate revenue that recovers costs and provides for a reasonable return on investment per customer class. The term "cost" covers both expenses, including taxes, and the return on investment. The total cost to serve a particular class varies depending on its 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 class revenues resulting in each class earning its required return on invested capital, we say that "parity" has been reached. This is typically characterized as 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.

Q. Do the G Schedules vary depending on the generation methodology used?

A. Aside from the obvious difference in generation, minor differences in the allocation of general plant, administrative and general expenses, and income taxes cause the schedules to vary.

Q. In the rate design process, did you achieve parity?

A. Parity was not achieved. However, classes of service were moved significantly in that direction. The impact on customers of a full movement to parity must be weighed against the benefits of moving to parity. The Company's approach promotes "gradualism." It avoids large percentage differences in class revenue increases. In other words, while we shifted rates for each customer class toward cost-based rates, we also balanced that factor with other important factors, including gradualism and avoiding "rate shock."

VII. RATE DESIGN.

Q. What are the Company's requested rate design changes?

A. TEP requests that the Commission:

A. Accept TEP's unbundling methodology;

B. Affirm the Company's use of the OATT Rate for transmission and ancillary services;

C. Approve the Company's Plan for expanding Residential and General Service Time-of-Use service. For Residential customers (Pricing Plan R-01) and Small General Service customers (Pricing Plan GS-10), place new customers, customers moving from one location to another, and customers with meter change-outs on the Company's proposed TOU rates (R-70N and GS-76N), and freeze existing non-TOU rates (i.e., close to new subscription but retain for certain existing customers);

D. Place all Large General Service customers (Pricing Plan GS-13) and Large Light and Power customers (Pricing Plan LLP-14) on proposed TOU rates (Pricing Plans GS-85N and LLP-90N);

E. Replace current TOU and Guarantee Home Rates (Pricing Plans R-201B and R-201C) with newly designed Pricing Plans R-201BN and R-201CN. Pricing Plan R-201A will be frozen (i.e., closed to new subscription but retained for certain existing customers);

F. Accept the TOU periods for the proposed TOU rates;

G. Implement the Company's proposed inverted-block (tiered) structure for Residential customers and for General Service customers in plans generally applicable to customers with loads less than 200 kW;

H. Accept the Company-proposed cost-based customer charges, subject to a $3.50 per month cap on increases for Residential and General Service customers; and

I. Accept the Company's proposed revenue changes by class.

A. <u>Unbundling Methodology</u>.

Q. Please describe the unbundling methodology proposed by the Company.

A. Consistent with the approach approved in the 1999 Settlement Agreement, TEP has proposed a set of unbundled tariffs rendering the Company neutral between direct access and full requirements. This approach ensures that energy service providers, billing service providers, metering service providers, or meter-reading service providers have a reasonable opportunity to serve customers if they can provide service at or below the cost-based level reflected by the unbundling.

Q. What are the key features of unbundling.

A. The most important criterion is that functions that can be provided by third parties be priced at TEP's cost. This is an economically efficient price signal in that a third party provider that can undercut TEP's unbundled price will be able to attract customers. In this instance, customers save money and services are provided by the lower cost provider. Likewise, if a third party is unable to provide services at a lower cost, TEP will continue to provide the service. Functions provided exclusively by TEP (delivery-type functions) will be provided at an average price equal to the total average price associated with a class' proposed revenue (total of all functions) less the average price associated with functions provided by a third parties. If one class of service subsidizes another - for example, general service subsidizes residential – delivery-type charges will reflect the subsidies. Residential delivery-type charges would be set under cost and general service-type charges will be set over cost.

Q. Is the 1999 unbundling methodology still appropriate today?

A. Yes. As a practical matter, all of TEP's customers are "Standard Offer" customers that take fully bundled service. However, TEP is still obligated under Commission rules to provide unbundled rates. The purpose for unbundling now is the same as it was in 1999 – to provide an opportunity for competition for certain services.

Q. Where are the unbundled rates set forth?

A. Unbundled rates are shown in the tariffs attached to my Direct Testimony as Exhibit DBE-2 (Proposed Market Tariffs), Exhibit DBE-3 (Proposed Cost-of-Service Tariffs), and Exhibit DBE-4 (Proposed Hybrid Tariffs). Both clean and redlined versions of the tariffs are provided.

B. Transmission - OATT Rate.

Q. Please describe the OATT Rate.

A. The OATT is a demand-based rate approved at FERC that is applicable to TEP's transmission and ancillary services. It is divided into an EHV (Extra High Voltage) and a non-EHV portion. The EHV charge is $2.259 per kW-month and the non-EHV charge is $0.757 per kW-month. TEP's ACC jurisdictional retail customers use both systems to bring energy from the source to the TEP distribution system.

Q., Please describe how the OATT rate is used.

A. Transmission has been treated as outside the ACC jurisdiction. As such, ACC jurisdictional retail customers pay transmission costs based on the FERC-approved rate. Transmission expenses have been calculated based on the filed FERC OATT rate, and the retail jurisdiction's demand billing determinants. This expense is handled as if the transmission function were a separate entity. In the embedded cost of service study, the calculated transmission expense replaces the study's original transmission components. This approach will be used for each of the Methodologies.

Q. Will the OATT Rate appear on customers bills?

A. Yes. For each class of service, a simple rate per kWh is calculated. These energy rates are based on the demand rates in the FERC OATT, but are can be applied when demand billing determinants are not available on a customer by customer basis.

Q. Why is use of the OATT Rate appropriate?

A. In the 1999 Settlement Agreement and Decision No. 62103, the Commission approved an unbundled tariff for TEP that opened the system to direct access. In the direct access paradigm, the transmission function is open to all users and is subject to FERC

jurisdiction. TEP, the local distribution/delivery company, cannot receive preferential treatment relative to other firm wholesale customers, even though UniSource Energy owns both the local distribution/delivery assets and the transmission assets. The separation between the distribution/delivery function and the transmission function is real; every professional UniSource Energy employee receives training on the separation of these functions and the negative consequences of transgression. While open access has not "blossomed" as anticipated and customers see no practical difference between the provider choices today than choices twenty years ago, direct access is "on the books" and transmission is separated. Since the Commission has not eliminated the requirement to file unbundled tariffs, it is not only consistent but necessary to treat transmission as if it were provided by an independent, unaffiliated company. As such, the TEP distribution/delivery company would pay the transmission company for the service used according to the OATT approved by FERC. The transmission costs would be recorded as an expense to TEP, and all transmission in TEP's cost of service studies would be removed from the retail jurisdiction. This is what TEP has done in this filing.

Q. What is the purpose of Rider 5, the Transmission Cost Adjustment Charge (TCA Charge)?

A. TEP is requesting Commission approval of this TCA Charge, attached as Exhibit DBE-5 to my Direct Testimony. It is designed to help true-up revenue collection to match TEP retail transmission and ancillary service expenses. These expenses are based on the application of the Company's FERC-approved OATT rates to TEP's retail jurisdictional sales. The Company proposes that the TCA Charge be adjusted annually. In the event that the Company's FERC-approved OATT changes, TEP would file an additional recalculated TCA Charge, unless the regular annual adjustment addresses the OATT change. The TCA charge is based upon the prior year's annual Transmission and Ancillary Service costs and retail energy sales. The TCA Charge will be applied

volumetrically to kilowatt-hour sales under applicable electric schedules, and will apply to all retail system sales. It will not vary by class of service.

Q. Have transmission cost adjustment charges previously been approved by the Commission?

A. Yes. The Commission has approved a similar adjustment clause for Arizona Public Service Company.

C. <u>Time-Of-Use Rates For Residential And General Service (<200 kW) Customers</u>.

Q. Does TEP currently have TOU rates?

A. Yes. However subscription to the current Time-of-Use programs is relatively small compared to non-TOU subscription. In part, this is due to a subscription cap on General Service Time-of-Use (Pricing Plan C76). However most time-of-use plans do not have caps. Customers sometimes do not believe that the potential to save compensates them for the "inconvenience" of TOU. TEP plans to increase efforts to educate customers about the benefits of our new TOU proposals, including savings opportunities. Proposed TOU rates have been redesigned to focus on relatively short, "super-peak" periods (usually 4 consecutive hours per day). This type structure not only offers customers many opportunities to "work around" the peak, it is also well suited to helping reduce peak demand in the extreme weather conditions of the TEP service territory.

Q. Why is TEP proposing additional TOU rates?

A. Including TOU rates within the overall rate design will provide a stronger price signal to customers to shift load out of the critical peak period. Reducing peak means that less power will be needed when it is most costly. Consequently, less power will have to be

purchased from the spot market during peak times. This will result in savings for the Company and its customers. TOU customers who "shave" the peak and "fill in" the off-peak valleys reduce the average price that they pay for electricity. A TOU rate rewards customers who help lower average system costs. As a DSM measure, TOU is a low-cost program with large benefits in reducing peak. Requiring new customers to be on TOU tariffs will send price signals that more accurately reflect the additional costs needed to serve new load. Further, reducing peak period demand and shifting consumption to off-peak times helps increase load factor, which also reduces cost through the more intensive utilization of fixed resources. The tariffs setting forth the proposed TOU pricing plans are attached as part of Exhibits DBE-2, 3 and 4 to my Direct Testimony.

Q. Are you proposing TOU rates under all three Methodologies?

A. Yes. TEP faces a need to control peak demand regardless of the methodology chosen. Constraints apply over the generation, transmission and distribution functions. Time-of-Use helps defer capacity additions under all methodologies. Moreover, customers should have the opportunity to achieve savings through their usage patterns under each methodology.

Q. If TOU tariffs are so beneficial, why are you only recommending that new Residential (Pricing Plan R 01) and General Service (Pricing Plan GS-10) customers be on TOU tariffs?

A. It is impractical to immediately place all these customers on the new TOU plans because of the substantial number of meters that would need to be replaced under such a comprehensive program. Simply stated, we do not want to instantly erode the savings to be achieved by load shifting with the costs associated with comprehensive meter replacement. Meter replacement for existing customers could be phased in over time, so that the meter change-out costs never completely outpace the load shifting savings.

Placing new customers on TOU is a cost effective and simple way of phasing-in the new TOU program.

Q. Why should TOU rates be mandatory?

A. It will only be mandatory for new customers to the system, although existing customers would use TOU rates if they replace their meters. By making the rate mandatory, we ensure that customers are paying for the costs they impose on the system. Absent mandatory TOU, a non TOU customer using a relatively large proportion of his energy during on-peak times places the cost of his consumption on other customers. I believe that shifting of the burden of cost from the responsible party, the peak user, to other customers is fundamentally unfair. Appropriate rate design should reflect cost causation.

Q. Could the Company achieve the same goals by keeping non-TOU rates open, but setting non-TOU rates at a higher average price to reflect their less desirable usage profile?

A. No. I believe that to do so would only prolong the problem the Company experiences with excessive load in the critical peak period. Rates for non-TOU customers must reflect the reality that these customers' costs may be higher. While TEP could structure such rates, any modification made in the rate-setting process could destroy any effective price signals in a non-TOU rate. Without effective price signals that customers understand and pay attention to, fixing old subsidies and inequities is unnecessarily prolonged. I do not believe that it is good public policy to continue to allow our highest cost-to-serve customers to pass on their costs to other system customers. We have an obligation to design rates that are fair to *every* customer, including ensuring that the principal cost-causers pay rates that reflect the true cost of power that they use.

D. <u>TOU Rates – Large General Service And Large Light And Power</u>.

Q. You are, however, recommending that all new *and existing* Large General Service and Large Light and Power customers be put on a TOU tariff?

A. Yes. In contrast to the Residential and Small General Service customers, large commercial and industrial customers typically will be immediately transferred to a TOU alternative. There are only a small number of these large customers, and the current meters already have TOU capability. Hence, the potential load shifting savings should exceed the cost of any metering or billing modifications.

E. <u>Time-Of-Use And Residential Guarantee Rates</u>.

Q. Please summarize your time-of-use rate proposals and indicate which rates will be eliminated, which will be frozen, and which are open to new subscription.

A. For Residential customers, the current non-TOU Pricing Plan R-01 and non-TOU Guarantee Home Pricing Plan R-201A will be frozen to existing customers. Current Residential Pricing Plans R-21 and R-70 will be eliminated, and Time-of-Use Residential Pricing Plan R-70N will be open to new customers. Residential Guarantee Home Pricing Plans R-201B, and R-201C will be replaced by Pricing Plans R-201BN, and R-201CN. For General Service customers, the current non-TOU Pricing Plan GS-10 will be frozen to existing customers. Current General Service Pricing Plan GS-76 will be eliminated, and Time-of-Use General Service Pricing Plan GS-76N will be open to new customers. Large General Service Pricing Plans GS-13, GS-85A and GS-85F will be eliminated and replaced by GS-85N. Large Light and Power Pricing Plans LLP-14, LLP-90, and LLP-90F will be eliminated and replaced by Time-of-Use Pricing Plan LLP-90N.

F. TOU Rates – Determination Of Time Periods.

Q. Did you perform the analysis to determine which hours to include in the peak period versus the off-peak period?

A. Yes. The selection of peak and shoulder hours was based on whether the load for a particular hour differs significantly from daily peak load. Whether a statistically-significant difference exists depends on the mean and standard deviation of hourly load. Through the use of confidence interval concepts, I classified the hours as peak, shoulder, and off-peak. Shoulder hours applied only in the summer months (May through October).

Q. Please describe the results of your analysis.

A. The peak period was limited to the most critical hours of the day. The summer (May through October) peak is 2 p.m. to 6 p.m. There is an additional two hours of summer shoulder on either side of the peak period (Noon to 2 p.m. and 6 p.m. to 8 p.m.), resulting in a total of four hours in the shoulder. Consequently, 16 hours of each summer day are off-peak. In the winter (November through April), there is a morning peak (6 a.m. to 10 a.m.) and an evening peak (5 p.m. to 9 p.m.), for a total of eight hours per day of winter on-peak. There is no shoulder in the winter. Consequently, 16 hours of each winter day are also off-peak. Large numbers of off-peak hours offer convenient opportunities for customers to shift usage out of peak and shoulder periods.

G. Residential / Small Commercial Inverted Block (Tiered) Rates.

Q. Please discuss the Residential and Small General Service rate design.

A. First, existing residential and small general service customers will have an opportunity to remain on the non-TOU pricing plans, or switch to the new TOU rates. There is no service charge for switching to the TOU alternative.

Second, there are two main changes in the non-TOU pricing plans. The first feature of non-TOU residential and small commercial rate design is the introduction of an inverted block structure aimed at encouraging conservation. Residential customers will now be able to purchase their first 500 kWh per month at a one-cent per kWh discount relative to second-block consumption (over 500 kWh per month). Third-block consumption (*i.e.*, over 3,500 kWh per month) will be priced at a two-cents per kWh *premium* over second block consumption. For Small General Service customers the first 500 kWh per month will be at one cent per kWh discount relative to the second-block kWhs, while kWhs in excess of 55,000 per month will be at a one cent premium relative to the second-block kWhs. This allows customers who conserve to be rewarded for their efforts. Like the Company's TOU and DSM proposals, the inverted-block structure is aimed at deferring capacity additions, reducing peak demand, and keeping costs low. The tiered structure proposed by the Company is sometimes referred to as "Lifeline Block Rate". Under this rate, customers are able to purchase an initial block of energy for basic needs at a reduced price per unit.

H. Customer Charge Changes.

Q. Are you proposing monthly customer charge increases on most pricing plans?

A. Yes. The Company is asking to set monthly customer charges at cost-based levels indicated in the CCOSS. This will help lessen the subsidization of low use customers by high use customers. While the Company understands that energy conservation is an important policy goal, this must also be balanced with the ratemaking principle that those who cause costs should pay a reasonable share of those costs. The Company seeks to strike this balance through its inverted block rate design and its proposed customer charges. Moreover, the Company notes that the proposed changes to the customer charges for Residential and General Service customers result in increases of no more than $3.50 per customer per month. The charges are shown in Schedule H. Finally, the proposed customer charges are all sufficient to cover TEP's cost of providing services that currently are eligible to be provided by third parties under direct access, such as meter reading service providers, metering service providers and billing service providers. This facilitates third-party service provider participation in the direct access market.

I. Lifeline Discount for Low-Income Customers.

Q. Please describe TEP's existing Lifeline Discount for low-income customers.

A. Pricing Plan R-06 (Residential Lifeline Discount) allows qualified customers to receive a discount of $8.00 per month off the customer's bill. This notwithstanding, the minimum monthly bill shall be zero. That is, the $8.00 monthly discount cannot be used to create a negative monthly bill (i.e., when the monthly bill before the discount is less than $8.00, and an $8.00 discount would otherwise create a bill credit for the month).

Q. Will TEP's proposed Lifeline Rate Block eliminate the Lifeline Discount for low-income customers?

A. Absolutely not. TEP's qualified low-income customers will still be eligible to receive the Lifeline Discount described above.

J. Proposed Revenue Changes By Class.

Q. Please list the proposed revenue changes by customer class.

A. The proposed average revenue change by customer class under each Methodology is as follows:

	Market	Cost of Service	Hybrid
Residential:	19.4%	23.8%	18.2%
General Service:	17.8%	20.8%	12.3%
Large Light and Power:	26.8%	25.1%	17.1%
Lighting:	22.1%	26.7%	12.2%
Public Authority:	33.8%	11.7%	23.6%
Total	21.9%	23.0%	14.9%

The specific revenue changes are set forth in Schedule H-4.

VI. SERVICE AND LATE FEE ADJUSTMENTS.

Q. Please describe changes in Service and Late Fees and associated adjustments.

A. Service and Late Fees are an "other revenue" item. As such, TEP does not benefit from an increase in the fees. Fee increases are offset by revenue reductions from other customers. Fees have been adjusted to help ensure that customers who cause a cost also incur that cost.

The key changes in Service and Late Fees are:

i. Establishment of a Late Fees at 1.5% per month, which is consistent with industry standards.

ii. Increase the charge for Service Connect or Reconnect under usual operating procedures – regular working hours, to $22.00 from $13.50;

iii. Increase the charge for Service Connect or Reconnect under usual operating procedures – hours other than regular working hours, to $51.00 from $35.00;

iv. Increase the charge for Service Connect or Reconnect under usual operating procedures – Regular working hours – Three Phase Metering , to $71.00 from $13.50;

v. Increase the charge for customer requested Meter Rereads to $13 from $10; and

vi. Increase the charge for a metering field test to $144 from $40.

The proposed changes in service fees are cost-based.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT

DBE-1

Rider 4
Termination Costs Regulatory Asset Charge ("TCRAC")

The TCRAC for the period January 1, 2009 through December 31, 2009 shall be $0.012622 per kWh, applicable to all retail Customers.

Notes

1. The planned amortization schedule for the Termination Costs Regulatory Asset is contained in the Calculation of Termination Cost Regulatory Asset Charge, filed with the Commission July 2, 2007, as Exhibit KCG-2 to the direct testimony of Mr. Kentton Grant ("Termination Costs Regulatory Asset Amortization Schedule"). The actual amortization of the Termination Costs Regulatory Asset will depend on actual retail kWh sales.

2. To the extent that actual retail kWh sales in a given year are higher than the projected retail kWh sales for that year, the amortization attributed to that year will be increased, decreasing the unamortized balance of cost that remains to be collected.

3. To the extent that actual retail kWh sales in a given year are lower than the projected retail kWh sales for that year, the amortization attributed to that year will be less than the amount shown in the Calculation of Termination Cost Regulatory Asset Charge, resulting in a higher unamortized balance than would have occurred if sales were as projected.

4. Large Light and Power Service customers with contracts at negotiated rates will be assessed the TCRAC and recorded by the Company. Payment of such TCRAC assessments shall be arranged between the Company and Customer upon expiration of the current contract.

EXHIBIT

DBE-2

CLEAN VERSION

Pricing Plan R-01 FROZEN
Residential Electric Service

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single phase or three phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter; however, electric water heating may be metered separately.

Not applicable to resale, breakdown, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, nominal 120/240 volts.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service $ 9.00 per month

Customer Charge, Three Phase service $15.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.014530	$0.013968
Next 3,000 kWh	$0.016327	$0.015848
3,501 kWh and above	$0.028391	$0.019948

Fixed Must-Run, all kWh $0.001047 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.51 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.29 per month
Customer Delivery	$3.40 per month

Note: Additional meter service charge of $6.00 per month for Three Phase Service.

Energy (kWh) and Demand Charges (kW):

Delivery

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.000568	$0.000006
Next 3,000 kWh	$0.002365	$0.001886
3,501 kWh and above	$0.014429	$0.005986

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Fixed Must-Run $0.001047 per kWh

Market Generation Charge ("MGC")

The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and

Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan R-02 FROZEN
Residential Electric Water Heating Service

AVAILABILITY
This rate is limited to installations and customers served under Pricing Plan No. 2 on the effective date of this tariff sheet.

APPLICABILITY
To separately metered single phase residential off-peak water heating service where general residential service is also provided under Pricing Plan No. 1. When service under Pricing Plan No. 2 is discontinued, the Company will either combine usage and bill under Pricing Plan No. 1 or modify the service entrance equipment so all service is supplied through the Pricing Plan No. 1 meter.

Not applicable to three phase service, resale, breakdown, standby, auxiliary, or any other service except off-peak water heating in accordance with the provisions of this pricing plan.

Where service other than water heating to which this rate is applicable has been taken hereunder, the regular rate for such service shall be applied on a monthly basis to all consumption billed hereunder during the previous twelve months, less the aggregate of payments made hereunder for the same period of time. The regular rate shall continue to apply until the unauthorized service is permanently separated from the off-peak water heating service.

CHARACTER OF SERVICE
Single phase, 60 Hertz, nominal 120/240 volts.

Service may be controlled by the Company by disconnecting electricity during certain periods of the day not exceeding 8 hours in any 24-hour period, as determined by the Company from time to time.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges:

Delivery, all kWh	$0.016962 per kWh
Fixed Must-Run, all kWh	$0.001047 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy:

Delivery	$0.003000 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Fixed Must-Run	$0.001047 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

The electric water heating equipment and installation shall conform to the Company's requirements and be for normal domestic use. The heater shall be of the storage type and not less than 30-gallon capacity. For a water heater equipped with one heating element, the rating of the heating element shall not exceed 6,000 watts. For a water heater equipped with more than one heating element, the rating of any such heating element shall not exceed 6,000 watts, and, if the total of the ratings of the elements exceeds 6,000 watts, they shall be thermostatically interlocked so that they cannot operate simultaneously and thereby exceed 6,000 watts. The Customer shall provide the necessary wiring to permit the installation of the Company's metering and control equipment.

The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan R-70N
Residential Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Service is available to individual private dwellings and individually metered multi-family units when all service is supplied at one point of delivery and energy is metered through one meter; however, controlled off-peak electric water heating may be metered separately.

Not applicable to three phase service, resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

Service under this pricing plan will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
Single phase, 60 Hertz, nominal 120/240 volts.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge: $9.00 per month

Energy Charges:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.0021912	$0.014015	$0.014224
Next 3,000 kWh	$0.055580	$0.036971	$0.026580
3,501 kWh and above	$0.060224	$0.040919	$0.025724

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.021912	$0.014085
Next 3,000 kWh	$0.040902	$0.014185
3,501 kWh and above	$0.042885	$0.014385

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak: there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

If a Summer or Winter holiday falls on Saturday, the preceding Friday is designated off-peak; if a holiday falls on Sunday, the following Monday is designated off-peak.

Energy Charges continued:

Fixed Must-Run $0.001047 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.51 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.29 per month
Customer Delivery	$3.40 per month

Energy:

Delivery

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.007950	$0.000053	$0.000262
Next 3,000 kWh	$0.041618	$0.023009	$0.012618
3,501 kWh and above	$0.046262	$0.026957	$0.011762

Pricing Plan R-70N
Residential Time-of-Use

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.007950	$0.000123
Next 3,000 kWh	$0.026940	$0.000223
3,501 kWhs and above	$0.028923	$0.000423

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Fixed Must-Run	$0.001047 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plans:
R-201A FROZEN,
R-201BN AND R-201CN
Special Residential Electric Service

AVAILABILITY
Throughout the entire area where facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To single phase electric service in individual residences as described in current program details when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this Schedule requires that the customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below and that the customer's home conform to the standards of the Heating, Cooling and Comfort Guarantee program as in effect at the time of subscription to this Schedule. Notwithstanding the above, the customer's use of solar energy for any purpose shall not preclude subscription to this Schedule. Two different Options are available under this Schedule: BN, & CN. Subscription eligibility requirements are as follows:

Option A: This option is FROZEN to new customers.
Option BN: Customer must meet above conditions and must purchase under the time-of-use structure.
Option CN: Customer must meet above conditions and must use either (i.) solar equipment for water heating requirements during the year or (ii.) an electric heat pump water heater, or both (i.) and (ii.), and must purchase under the time-of-use structure applicable to Option CN.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
Single phase, 60 Hertz, nominal 120/240 volts.

PRICE UNDER OPTION A
A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Minimum Customer Charge $ 9.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.048250	$0.029000	$0.014500
Next 3,000 kWh	$0.050750	$0.022750	$0.014250
3,501 kWh and above	$0.055750	$0.024750	$0.018250

Fixed Must-Run, all kWh $0.001047 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

PRICE UNDER OPTION BN
A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Minimum Customer Charge $ 9.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.028962	$0.023962	$0.018962
Next 3,000 kWh	$0.033962	$0.028962	$0.023962
3,501 kWh and above	$0.038962	$0.033962	$0.028962

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.026462	$0.021462	$0.016462
Next 3,000 kWh	$0.031462	$0.026462	$0.021462
3,501 kWh and above	$0.036462	$0.031462	$0.026462

The Mid-Summer and Remaining Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day:

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.
Off-Peak is 8:00 p.m. to 12:00 p.m.
On-Peak is 2:00 p.m. to 6:00 p.m.

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.018962	$0.013962
Next 3,000 kWh	$0.023962	$0.018962
3,501 kWh and above	$0.028962	$0.023962

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day:

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: there are no shoulder peak periods in the winter.
Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

If a Summer or Winter holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

Energy Charges continued:

Fixed Must-Run $0.001047 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

PRICE UNDER OPTION CN
A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Minimum Customer Charge $ 9.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.028962	$0.023962	$0.018962
Next 3,000 kWh	$0.033962	$0.028962	$0.023962
3,501 kWh and above	$0.038962	$0.033962	$0.028962

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.026462	$0.021462	$0.016462
Next 3,000 kWh	$0.031462	$0.026462	$0.021462
3,501 kWh and above	$0.036462	$0.031462	$0.026462

The Mid-Summer and Remaining Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day:

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.
Off-Peak is 8:00 p.m. to 12:00 p.m.
On-Peak is 2:00 p.m. to 6:00 p.m.

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.018962	$0.013962
Next 3,000 kWh	$0.023962	$0.018962
3,501 kWh and above	$0.028962	$0.023962

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day:

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak – there are no shoulder peak periods in the winter.
Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

If a Summer or Winter holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

Energy Charges continued:

Fixed Must-Run $0.000322 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

BUNDLED STANDARD OFFER SERVICE R-201A FROZEN, R-201BN AND R201CN CONSIST OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.51 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.29 per month
Customer Delivery	$3.40 per month

Energy:

Delivery **(FOR OPTION A ONLY):**

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.034288	$0.015038	$0.000538
Next 3,000 kWh	$0.036788	$0.008788	$0.000288
3,501 kWh and above	$0.041788	$0.010788	$0.004288

Delivery **(FOR OPTION BN ONLY):**

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.015000	$0.010000	$0.005000
Next 3,000 kWh	$0.020000	$0.015000	$0.010000
3,501 kWh and above	$0.025000	$0.020000	$0.015000

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.012500	$0.007500	$0.002500
Next 3,000 kWh	$0.017500	$0.012500	$0.007500
3,501 kWh and above	$0.022500	$0.017500	$0.012500

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.005000	$0.000001
Next 3,000 kWh	$0.010000	$0.005000
3,501 kWh and above	$0.015000	$0.010000

Delivery **(FOR OPTION CN ONLY):**

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.015000	$0.010000	$0.005000
Next 3,000 kWh	$0.020000	$0.015000	$0.010000
3,501 kWh and above	$0.025000	$0.020000	$0.015000

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.012500	$0.007500	$0.002500
Next 3,000 kWh	$0.017500	$0.012500	$0.007500
3,501 kWh and above	$0.022500	$0.017500	$0.012500

Pricing Plans:
R-201A FROZEN,
R-201BN AND R-201CN
Special Residential Electric Service

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.005000	$0.000001
Next 3,000 kWh	$0.010000	$0.005000
3,501 kWh and above	$0.015000	$0.010000

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Fixed Must-Run	$0.001047 per kWh

Market Generation Charge ("MGC")

The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan GS-10 FROZEN
General Service

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE
A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service $ 9.00 per month

Customer Charge, Three Phase service $16.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.025525	$0.020680
Next 54,500 kWh	$0.035525	$0.030680
55,000 kWh and above	$0.040525	$0.035680

Fixed Must- Run, all kWh $0.001016 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING
The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$2.12 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.23 per month
Customer Delivery	$2.85 per month

Note: Additional meter service charge of $7.00 per month for Three Phase Service.

Energy Charges:

Delivery:

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.025525	$0.020680
Next 54,500 kWh	$0.035525	$0.030680
55,000 kWh and above	$0.040525	$0.035680

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003293 per kWh
System Benefits	$0.000443 per kWh
Transmission	$0.007298 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Fixed Must-Run	$0.001016 per kWh

Market Generation Charge ("MGC")

The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

Market Generation Credit ("MGC")

The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan GS-11 - FROZEN
Mobile Home Park Electric Service

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

To mobile home parks for service through a master meter to two or more mobile homes, provided each mobile home served through such master meter will be individually metered and billed by the park operator in accordance with applicable Orders of the Arizona Corporation Commission. Electric service to the park's facilities used by its residents may be supplied under this schedule only if such facilities are served through a master meter which serves two or more mobile homes.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service	$ 9.00 per month
Customer Charge, Three Phase service	$16.00 per month
Energy Charges:	
Summer (May – October, all kWh	$0.027156
Winter (November – April), all kWh	$0.017156
Fixed Must-Run, all kWh	$0.001016

+ Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$2.12 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.23 per month
Customer Delivery	$2.85 per month

Note: Additional meter service charge of $7.00 per month for Three Phase Service.

Energy Charges (kWh):

Delivery:

Summer (May – October), all kWh	$0.027156 per kWh
Winter (November – April), all kWh	$0.017156 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003293 per kWh
System Benefits	$0.000443 per kWh
Transmission	$0.007298 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Fuel Must-Run	$0.001016 per kWh

Market Generation Charge ("MGC")

The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan GS-76N
General Service Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service	$ 9.00 per month
Customer Charge, Three Phase service	$16.00 per month

Energy Charges:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.062389	$0.026579	$0.012889
Next 54,500 kWh	$0.072389	$0.036579	$0.022889
55,000 kWh and above	$0.077389	$0.041579	$0.027889

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.051360	$0.001860
Next 54,500 kWh	$0.061360	$0.011860
55,000 kWh and above	$0.066360	$0.016860

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak: there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

Fixed Must-Run, all kWhs $0.001016 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$2.12 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.23 per month
Customer Delivery	$2.85 per month

Note: Additional meter service charge of $7.00 per month for Three Phase Service.

Energy Charges:

Delivery:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.062389	$0.026519	$0.012889
Next 54,500 kWh	$0.072389	$0.036519	$0.022889
55,000 kWh and above	$0.077389	$0.041519	$0.027889

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.051360	$0.001860
Next 54,500 kWh	$0.061360	$0.011860
55,000 kWh and above	$0.066360	$0.016860

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003293 per kWh
System Benefits	$0.000443 per kWh
Transmission	$0.007298 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Fixed Must-Run	$0.001016 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan GS-31
Interruptible Agricultural Pumping

AVAILABILITY

Available for interruptible service to agricultural pumping customers throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

Applicable to separately metered interruptible agricultural water pumping service for irrigation purposes of the Customer only.

Not applicable to resale, breakdown, standby, auxiliary, or any other service except agricultural pumping in accordance with the provisions of this rate schedule.

CHARACTER OF SERVICE

Three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges:

Summer (May – October)	$0.004309 per kWh
Winter (November – April)	$0.004309 per kWh
Fixed Must-Run	$0.001016 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DETERMINATION OF HORSEPOWER FOR BILLING
Horsepower connected shall be the manufacturer's nameplate rating of all equipment of Customer connected for service under this schedule, but not less than 60 hp.

MINIMUM BILL

The Customer guarantees that its load shall be sufficient such that a summation of all the above payments shall be not less than $30.00 per hp connected per contract year (which shall be from April 1 to March 31 of the following year) and in no event less than $1,800.00 per contract year. Minimum payments at the rate of $2.50 per hp of motors connected, but not less than $150.00 shall be made monthly.

If during the contract year the total payments exceed the annual guarantee of $30.00 per hp connected but not less than $1,800.00, then the Customer shall be credited the difference between the amount actually paid during the contract year and the amount which would have been paid had the monthly minimum charge not been applied.

TERMS AND CONDITIONS OF SERVICE

1. Customer must furnish, install, own, and maintain at each point of delivery all necessary Company approved equipment which will enable the Company to interrupt service with its master control station.

2. Service may be interrupted by Company during certain periods of the day not exceeding six hours in any 24-hour period.

3. Company will endeavor to give customer one hour notice of impending interruption; however, service may be interrupted without notice should Company deem such action necessary.

4. Where service other than agricultural pumping to which this rate is applicable has been taken hereunder, the general service rate shall be applied on a monthly basis to all usage billed hereunder during the previous twelve months less the aggregate of payments made hereunder for the same period of time. The general service rate shall continue to apply until the unauthorized service is permanently separated from the agricultural pumping service.

5. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy Charges:	
Delivery:	
Summer (May – October)	$0.004309 per kWh
Winter (November – April)	$0.004309 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003293 per kWh
System Benefits	$0.000443 per kWh
Transmission	$0.007298 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000099 per kWh

Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Fixed Must-Run	$0.001016 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4

Transmission Credit – Rider No. 5.

Pricing Plan GS-85N
General Service Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge $371.88 per month

Demand Charges:
On-peak $3.00 per kW
Off-peak $1.00 per kW

Energy Charges:

	SUMMER (May – October)	WINTER (November – April)
On-peak, per kWh	$0.021062	$0.016380
Shoulder-peak, per kWh	$0.005146	N/A
Off-peak, per kWh	$0.000062	$0.012969

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak: there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

Fixed Must-Run, all kWhs $0.001016 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$223.13 per month
Meter Reading	$ 18.59 per month
Billing & Collection	$111.56 per month
Customer Delivery	$ 18.59 per month

Energy Charges:

Delivery:

On-peak	$3.00 per kW
Off-peak	$1.00 per kW

	SUMMER (May – October)	WINTER (November – April)
On-peak, per kWh	$0.021062	$0.016380
Shoulder-peak, per kWh	$0.005146	N/A
Off-peak, per kWh	$0.000062	$0.012969

Fixed Must-Run (See Must-Run Generation – Rider No. 2) $0.003293 per kWh

System Benefits $0.000443 per kWh

Transmission	$0.007298 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Fixed Must-Run	$0.001016 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan LLP-90N
Large Light and Power Service Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

CHARACTER OF SERVICE
Service shall be three phase, 60 Hertz, Primary Service, and shall be supplied directly from any 46,000 volt, or higher voltage, system at a delivery voltage of not less than 13,800 volts and delivered at a single point of delivery unless otherwise specified in the contract.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge $500.00 per month

Demand Charges:
On-peak $8.00 per kW
Off-peak $2.66 per kW

Energy Charges:

	Summer (May – October)	Winter (November - April)
On-Peak	$0.019327	$0.016955
Shoulder-Peak	$0.028545	N/A
Off-Peak	$0.008425	$0.004455

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak: there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

Fixed Must-Run, all kWhs $0.000861 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

PRIMARY SERVICE
The above rate is subject to Primary Service and Metering. The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers

POWER FACTOR ADJUSTMENT
The above rate is subject to a discount or a charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is above or below 90% lagging to a maximum discount of 13.0¢ per kW of billing demand per month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$300.00 per month
Meter Reading	$25.00 per month
Billing & Collection	$150.00 per month
Customer Delivery	$25.00 per month

Energy Charges:

Delivery:

On-peak	$8.00 per kW
Off-peak	$2.66 per kW

	Summer (May – October)	Winter (November - April)
On-Peak, per kWh	$0.019327	$0.016955
Shoulder-Peak, per kWh	$0.008425	N/A
Off-Peak, per kWh	$0.028545	$0.004455

Fixed Must-Run (See Must-Run Generation – Rider No. 2) $0.003408 per kWh

System Benefits	$0.000433 per kWh
Transmission	$0.006184 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000084 per kWh
Reactive Supply and Voltage Control	$0.000330 per kWh
Regulation and Frequency Response	$0.000320 per kWh
Spinning Reserve Service	$0.000867 per kWh
Supplemental Reserve Service	$0.000141 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Fixed Must-Run	$0.000861 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan PS-40
Municipal Service

AVAILABILITY

Available for Municipal Service where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

Applicable for service to the City of Tucson and City of South Tucson for Municipal buildings and grounds.

Not applicable to resale, breakdown, standby, or auxiliary service or to buildings used for residential purposes.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, at secondary voltage and subject to availability at point of delivery approved by the Company.

RATE

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges:

Summer (May – October, all kWh	$0.048952
Winter (November – April), all kWh	$0.038952
Fixed Must-Run, all kWhs	$0.000853

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy Charges:

Delivery:

Summer (May – October, all kWh	$0.048952
Winter (November – April), all kWh	$0.038952
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003289 per kWh

System Benefits	$0.000434 per kWh
Transmission	$0.006129 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000083 per kWh
Reactive Supply and Voltage Control	$0.000327 per kWh
Regulation and Frequency Response	$0.000317 per kWh
Spinning Reserve Service	$0.000860 per kWh
Supplemental Reserve Service	$0.000140 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Fixed Must-Run	$0.000853 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan PS-41
Traffic Signal and Street Lighting Service

AVAILABILITY
Available for service to the State, a county, city, town, political subdivision, improvement district, or a responsible person or persons for unincorporated communities for Traffic Signal and Street Lighting purposes where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Applicable to Customer owned and maintained traffic signals and public street and highway lighting.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery approved by the Company.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

All kWh @ $0.050196 per kWh

Fixed Must-Run, all kWh	$0.000661 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Delivery	$0.019894 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.002305 per kWh
System Benefits	$0.000413 per kWh
Transmission	$0.026736 per kWh
Transmission Ancillary Services	

System Control & Dispatch	$0.000363 per kWh
Reactive Supply and Voltage Control	$0.001427 per kWh
Regulation and Frequency Response	$0.001383 per kWh
Spinning Reserve Service	$0.003750 per kWh
Supplemental Reserve Service	$0.000612 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Fixed Must-Run, all kWh	$0.000661 per kWh

Market Generation Credit ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan PS-43
Municipal Water Pumping Service

AVAILABILITY
Available for service to the City of Tucson Water Utility and private water Companies where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Applicable for service to booster stations and wells used for domestic water supply.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as elected by Customer and subject to availability at point of delivery approved by the Company. Primary metering may be used by mutual agreement.

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges Firm Service:	
Summer (May – October), all kWh	$0.081989
Winter (November – April), all kWh	$0.071989
Energy Charges Interruptible Service:	
Summer (May – October), all kWh	$0.066989
Winter (November – April), all kWh	$0.065989
Fixed Must-Run, all kWh	$0.000853

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy Charges:

Delivery Firm Service:	
Summer (May – October), all kWh	$0.081989
Winter (November – April), all kWh	$0.071989

Delivery Interruptible Service:	
Summer (May – October), all kWh	$0.066989
Winter (November – April), all kWh	$0.065989
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003289 per kWh
System Benefits	$0.000434 per kWh
Transmission	$0.006129 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000083 per kWh
Reactive Supply and Voltage Control	$0.000327 per kWh
Regulation and Frequency Response	$0.000317 per kWh
Spinning Reserve Service	$0.000860 per kWh
Supplemental Reserve Service	$0.000140 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Fixed Must-Run	$0.000853 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TERMS AND CONDITIONS OF INTERRUPTIBLE SERVICE

1. Customer must furnish, install, own, and maintain at each point of delivery all necessary Company approved equipment which will enable the Company to interrupt service with its master control station.

2. Service may be interrupted by Company during certain periods of the day not exceeding six hours in any 24-hour period.

3. Company will endeavor to give Customer one hour notice of impending interruption; however, service may be interrupted without notice should Company deem such action necessary.

4. The interruptible load shall be separately served and metered and shall at no time be connected to facilities serving Customer's firm load. Conversely, the firm load shall be separately served and metered and shall at no time be connected to facilities serving Customer's interruptible load.

5. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan PS-50
Public Street Lighting Service

AVAILABILITY
Available for service for lighting public streets, alleys, thoroughfares, public parks, and playgrounds by use of Company's standard facilities where such service is contracted under this pricing plan by the state, a county, city, town, political subdivision, improvement district, or a responsible person or persons for unincorporated communities.

APPLICABILITY
Applicable to street lighting service from dusk to dawn and Company will own, operate, and maintain the street light system including lamps and globe replacements.

CHARACTER OF SERVICE
Multiple or series street lighting system at option of Company and at one standard nominal voltage.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
per unit per month	$10.39	$10.39	$10.39	$15.60	$24.06	$19.68	$3.63

Note:

The watt high pressure sodium lamps are charged per unit per month.

Per one pole addition and an extension of up to 100 feet of overhead service are charged per pole.

Underground Service is per 100 watt or less high pressure sodium lamp unit per month mounted on standard pole.

Fixed Must-Run, all kWh $0.000661 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

STANDARD LAMP UNITS, OVERHEAD SERVICE

(1) The standard 100 watt lamp unit for overhead service is a 9,500 lumen high pressure sodium unit, mounted on a four foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 25 feet above ground level.

(2) The standard 250 watt lamp unit for overhead service is a 27,500 lumen high pressure sodium unit, mounted on an eight foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 27 feet above ground level.

(3) The standard 400 watt lamp unit for overhead service is a 50,000 lumen high pressure sodium unit, mounted on an eighteen foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 35 feet above ground level.

(4) The standard 100 watt lamp unit for underground service is a 9,500 lumen high pressure sodium post top unit mounted on a pole approximately 15 feet above ground level.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Delivery	$9.75	$9.59	$9.25	$12.79	$19.59
Fixed Must-Run	$0.04	$0.05	$0.07	$0.17	$0.28
System Benefits	$0.01	$0.01	$0.01	$0.03	$0.05
Transmission	$0.44	$0.56	$0.80	$2.01	$3.21
Transmission Ancillary					
System Control & Load Dispatch	$0.01	$0.01	$0.01	$0.03	$0.04
Reactive Supply and Voltage Control	$0.02	$0.03	$0.04	$0.11	$0.17
Regulation and Frequency Response	$0.02	$0.03	$0.04	$0.10	$0.17
Spinning Reserve Service	$0.06	$0.08	$0.11	$0.28	$0.45
Supplemental Reserve Service	$0.01	$0.01	$0.02	$0.05	$0.07
Energy Imbalance Service: currently charged pursuant to the Company's OATT.					
Fixed Must-Run	$0.01	$.01	$0.02	$0.05	$0.08

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

SPECIAL PROVISIONS

(1) Installation of a light on an existing pole is subject to prior approval of Company.

(2) For underground service, where customer provides trenching up to 10 feet in accordance with Company's electric service requirements, customer shall be billed at the rates for overhead service.

(3) Extensions beyond 100 feet and all installations other than those addressed in this pricing plan will require specific agreements providing adequate revenue or arrangements for construction financing.

(4) The Customer is not authorized to make connections to this lighting circuit or to make attachments or alterations to the Company owned pole.

(5) If a Customer requests a relocation of a lighting installation, the costs of such relocation must be borne by the Customer.

(6) The Customer is expected to notify the Company when lamp outages occur.

(7) The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

(8) After the minimum contract period, if any, has expired, this agreement shall be extended from year to year unless written notice of desire to terminate is given by either party at least thirty (30) days prior to the end of any such annual extension date.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan. Any condition not provided for herein must be the subject of a separate written agreement.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan GS-51
Private Street and Area Lighting Service

AVAILABILITY
At any point where the Company in its judgment has facilities of adequate capacity and suitable voltage available.

APPLICABILITY
To any Customer for private street or outdoor area lighting where this service can be supplied from existing facilities of the Company.

Service is from dusk to dawn and the Company will install, own, operate, and maintain the complete lighting installation including lamp replacements.

Not applicable to resale service.

CHARACTER OF SERVICE
Multiple or series street lighting system at option of Company and at one standard nominal voltage.

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
per unit per month	$10.39	$10.39	$10.39	$15.60	$24.06	$19.68	$3.63

Note:

The watt high pressure sodium lamps are charged per unit per month.

Per one pole addition and an extension of up to 100 feet of overhead service are charged per pole.

Underground Service is per 100 watt or less high pressure sodium lamp unit per month mounted on standard pole.

Fixed Must-Run, all kWh $0.000661 per kWh

Market Generation Credit ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

STANDARD LAMP UNITS, OVERHEAD SERVICE

(1) The standard 100 watt lamp unit for overhead service is a 9,500 lumen high pressure sodium unit, mounted on a four foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 25 feet above ground level.

(2) The standard 250 watt lamp unit for overhead service is a 27,500 lumen high pressure sodium unit, mounted on an eight foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 27 feet above ground level.

(3) The standard 400 watt lamp unit for overhead service is a 50,000 lumen high pressure sodium unit, mounted on an eighteen foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 35 feet above ground level.

(4) The standard 100 watt lamp unit for underground service is a 9,500 lumen high pressure sodium post top unit mounted on a pole approximately 15 feet above ground level.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Delivery	$9.75	$9.59	$9.25	$12.79	$19.59
Fixed Must-Run	$0.04	$0.05	$0.07	$0.17	$0.28
System Benefits	$0.01	$0.01	$0.01	$0.03	$0.05
Transmission	$0.44	$0.56	$0.80	$2.01	$3.21
Transmission Ancillary					
System Control & Load Dispatch	$0.01	$0.01	$0.01	$0.03	$0.04
Reactive Supply and Voltage Control	$0.02	$0.03	$0.04	$0.11	$0.17
Regulation and Frequency Response	$0.02	$0.03	$0.04	$0.10	$0.17
Spinning Reserve Service	$0.06	$0.08	$0.11	$0.28	$0.45
Supplemental Reserve Service	$0.01	$0.01	$0.02	$0.05	$0.07
Energy Imbalance Service: currently charged pursuant to the Company's OATT.					
Fixed Must-Run	$0.01	$.01	$0.02	$0.05	$0.08

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

SPECIAL PROVISIONS

(1) Installation of a light on an existing pole is subject to prior approval of Company.

(2) For underground service, where customer provides trenching up to 10 feet in accordance with Company's electric service requirements, customer shall be billed at the rates for overhead service.

(3) Extensions beyond 100 feet and all installations other than those addressed in this pricing plan will require specific agreements providing adequate revenue or arrangements for construction financing.

(4) The Customer is not authorized to make connections to this lighting circuit or to make attachments or alterations to the Company owned pole.

(5) If a Customer requests a relocation of a lighting installation, the costs of such relocation must be borne by the Customer.

(6) The Customer is expected to notify the Company when lamp outages occur.

(7) The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

(8) After the minimum contract period, if any, has expired, this agreement shall be extended from year to year unless written notice of desire to terminate is given by either party at least thirty (30) days prior to the end of any such annual extension date.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan. Any condition not provided for herein must be the subject of a separate written agreement.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Rider 1
Adder Associated with Market Generation Credit

All prices in mills per kWh

	Mills per kWh
All customers up to 200 kW demand	
Summer kWh up to 115% of winter kWh	3.84
Summer kWh greater than 115% but less than or equal to 145% of winter kWh	4.44
Summer kWh greater than 145% but less than or equal to 175% of winter kWh	5.04
Summer kWh greater than 175% but less than or equal to 205% of winter kWh	5.64
Summer kWh greater than 205% of winter kWh	6.24
All customers from 200 kW to 3000 kW demand	
Summer kWh up to 106% of winter kWh	3.00
Summer kWh greater than 106% but less than or equal to 136% of winter kWh	3.48
Summer kWh greater than 136%	3.96
All customers 3000 kW demand and above	
Air Liquide	3.00
Fort Huachuca	3.00
Arizona Portland Cement	3.00
IBM	3.00
Asarco Mission 1	3.00
Asarco Mission 2	3.00
Asarco Silverbell	3.00
Cyprus	3.00
University of Arizona Main Campus	3.00
University of Arizona Health Sciences Center	3.00
University of Arizona Central Heating & Refrigeration Plant	3.00
Burr Brown	3.00
Davis Monthan Air Force Base	3.00
Raytheon	3.00
University Medical Center	3.00
Tucson Medical Center	3.00

REDLINED VERSION

Tucson Electric Power
The Energy People

Pricing Plan R-01 FROZEN
Residential Electric Service

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single phase or three phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter; however, electric water heating may be metered separately.

Not applicable to resale, breakdown, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, nominal 120/240 volts.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service	$ 9.00 per month
Customer Charge, Three Phase service	$15.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.014530	$0.013968
Next 3,000 kWh	$0.016327	$0.015848
3,501 kWh and above	$0.028391	$0.019948

Fixed Must-Run, all kWh $0.001047 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

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BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.51 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.29 per month
Customer Delivery	$3.40 per month

Note: Additional meter service charge of $6.00 per month for Three Phase Service.

Energy (kWh) and Demand Charges (kW):

Delivery

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.000568	$0.000006
Next 3,000 kWh	$0.002365	$0.001886
3,501 kWh and above	$0.014429	$0.005986

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Fixed Must-Run $0.001047 per kWh

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Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and

Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

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FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Fuel and Purchased Power

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.0	$0.0
Next 3,000 kWh	$0.0	$0.0
3,501 kWh and above	$0.0	$0.0

Tucson Electric Power
The Energy People

Pricing Plan R-02 FROZEN
Residential Electric Water Heating Service

AVAILABILITY
This rate is limited to installations and customers served under Pricing Plan No. 2 on the effective date of this tariff sheet.

APPLICABILITY
To separately metered single phase residential off-peak water heating service where general residential service is also provided under Pricing Plan No. 1. When service under Pricing Plan No. 2 is discontinued, the Company will either combine usage and bill under Pricing Plan No. 1 or modify the service entrance equipment so all service is supplied through the Pricing Plan No. 1 meter.

Not applicable to three phase service, resale, breakdown, standby, auxiliary, or any other service except off-peak water heating in accordance with the provisions of this pricing plan.

Where service other than water heating to which this rate is applicable has been taken hereunder, the regular rate for such service shall be applied on a monthly basis to all consumption billed hereunder during the previous twelve months, less the aggregate of payments made hereunder for the same period of time. The regular rate shall continue to apply until the unauthorized service is permanently separated from the off-peak water heating service.

CHARACTER OF SERVICE
Single phase, 60 Hertz, nominal 120/240 volts.

Service may be controlled by the Company by disconnecting electricity during certain periods of the day not exceeding 8 hours in any 24-hour period, as determined by the Company from time to time.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges:

Delivery, all kWh	$0.016962 per kWh
Fixed Must-Run, all kWh	$0.001047 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

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Pricing Plan R-02 FROZEN
Residential Electric Water Heating Service

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy:

Delivery	$0.003000 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Fixed Must-Run $0.001047 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

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Pricing Plan R-02_FROZEN
Residential Electric Water Heating Service

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

The electric water heating equipment and installation shall conform to the Company's requirements and be for normal domestic use. The heater shall be of the storage type and not less than 30-gallon capacity. For a water heater equipped with one heating element, the rating of the heating element shall not exceed 6,000 watts. For a water heater equipped with more than one heating element, the rating of any such heating element shall not exceed 6,000 watts, and, if the total of the ratings of the elements exceeds 6,000 watts, they shall be thermostatically interlocked so that they cannot operate simultaneously and thereby exceed 6,000 watts. The Customer shall provide the necessary wiring to permit the installation of the Company's metering and control equipment.

The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

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Must-Run Generation – Rider No. 2; ¶
Transmission and Ancillary Services – Rider No. 3; ¶
Termination Costs Regulatory Asset – Rider No. 4;¶
Transmission Credit – Rider No. 5.¶

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Must-Run Generation – Rider No. 2; ¶
Transmission and Ancillary Services – Rider No. 3; ¶
Termination Costs Regulatory Asset – Rider No. 4¶
Transmission Credit -- Rider No. 5.

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Must-Run Generation – Rider No. 2; ¶
Transmission and Ancillary Services – Rider No. 3;

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Tucson Electric Power
The Energy People

Pricing Plan R-70N
Residential Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Service is available to individual private dwellings and individually metered multi-family units when all service is supplied at one point of delivery and energy is metered through one meter; however, controlled off-peak electric water heating may be metered separately.

Not applicable to three phase service, resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

Service under this pricing plan will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
Single phase, 60 Hertz, nominal 120/240 volts.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge: $9.00 per month

Energy Charges:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.0021912	$0.014015	$0.014224
Next 3,000 kWh	$0.055580	$0.036971	$0.026580
3,501 kWh and above	$0.060224	$0.040919	$0.025724

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

Tucson Electric Power
The Energy People

Pricing Plan R-70N
Residential Time-of-Use

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.021912	$0.014085
Next 3,000 kWh	$0.040902	$0.014185
3,501 kWh and above	$0.042885	$0.014385

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak: there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

If a Summer or Winter holiday falls on Saturday, the preceding Friday is designated off-peak; if a holiday falls on Sunday, the following Monday is designated off-peak.

Energy Charges continued:

Fixed Must-Run $0.00104Z per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

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The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.¶
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BUNDLED STANDARD OFFER SERVICE CONSISTSOF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.51 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.29 per month
Customer Delivery	$3.40 per month

Energy:
Delivery

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SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.007950	$0.000053	$0.000262
Next 3,000 kWh	$0.041618	$0.023009	$0.012618
3,501 kWh and above	$0.046262	$0.026957	$0.011762

Tucson Electric Power
The Energy People

Pricing Plan R-70N
Residential Time-of-Use

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.007950	$0.000123
Next 3,000 kWh	$0.026940	$0.000223
3,501 kWhs and above	$0.028923	$0.000423

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Fixed Must-Run $0.001047 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

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Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plans:
R-201A FROZEN,
R-201BN AND R-201CN
Special Residential Electric Service

AVAILABILITY
Throughout the entire area where facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To single phase electric service in individual residences as described in current program details when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this Schedule requires that the customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below and that the customer's home conform to the standards of the Heating, Cooling and Comfort Guarantee program as in effect at the time of subscription to this Schedule. Notwithstanding the above, the customer's use of solar energy for any purpose shall not preclude subscription to this Schedule. Two different Options are available under this Schedule: BN, & CN. Subscription eligibility requirements are as follows:

Option A: This option is FROZEN to new customers.
Option BN: Customer must meet above conditions and must purchase under the time-of-use structure.
Option CN: Customer must meet above conditions and must use either (i.) solar equipment for water heating requirements during the year or (ii.) an electric heat pump water heater, or both (i.) and (ii.), and must purchase under the time-of-use structure applicable to Option CN.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
Single phase, 60 Hertz, nominal 120/240 volts.

PRICE UNDER OPTION A
A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Minimum Customer Charge $ 9.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.048250	$0.029000	$0.014500
Next 3,000 kWh	$0.050750	$0.022750	$0.014250
3,501 kWh and above	$0.055750	$0.024750	$0.018250

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Fixed Must-Run, all kWh $0.001047 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

PRICE UNDER OPTION BN
A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Minimum Customer Charge $ 9.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.028962	$0.023962	$0.018962
Next 3,000 kWh	$0.033962	$0.028962	$0.023962
3,501 kWh and above	$0.038962	$0.033962	$0.028962

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.026462	$0.021462	$0.016462
Next 3,000 kWh	$0.031462	$0.026462	$0.021462
3,501 kWh and above	$0.036462	$0.031462	$0.026462

The Mid-Summer and Remaining Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day:

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.
Off-Peak is 8:00 p.m. to 12:00 p.m.
On-Peak is 2:00 p.m. to 6:00 p.m.

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.018962	$0.013962
Next 3,000 kWh	$0.023962	$0.018962
3,501 kWh and above	$0.028962	$0.023962

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day:

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: there are no shoulder peak periods in the winter.
Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

If a Summer or Winter holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

Energy Charges continued:

Fixed Must-Run $0.001047 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

PRICE UNDER OPTION CN
A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Minimum Customer Charge $ 9.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.028962	$0.023962	$0.018962
Next 3,000 kWh	$0.033962	$0.028962	$0.023962
3,501 kWh and above	$0.038962	$0.033962	$0.028962

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.026462	$0.021462	$0.016462
Next 3,000 kWh	$0.031462	$0.026462	$0.021462
3,501 kWh and above	$0.036462	$0.031462	$0.026462

The Mid-Summer and Remaining Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day:
Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.
Off-Peak is 8:00 p.m. to 12:00 p.m.
On-Peak is 2:00 p.m. to 6:00 p.m.

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.018962	$0.013962
Next 3,000 kWh	$0.023962	$0.018962
3,501 kWh and above	$0.028962	$0.023962

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day:

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak – there are no shoulder peak periods in the winter.
Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

If a Summer or Winter holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

Energy Charges continued:

Fixed Must-Run $0.000322 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

BUNDLED STANDARD OFFER SERVICE R-201A FROZEN, R-201BN AND R201CN CONSIST OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.51 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.29 per month
Customer Delivery	$3.40 per month

Energy:

Delivery **(FOR OPTION A ONLY):**

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.034288	$0.015038	$0.000538
Next 3,000 kWh	$0.036788	$0.008788	$0.000288
3,501 kWh and above	$0.041788	$0.010788	$0.004288

Delivery (FOR OPTION BN ONLY):

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.015000	$0.010000	$0.005000
Next 3,000 kWh	$0.020000	$0.015000	$0.010000
3,501 kWh and above	$0.025000	$0.020000	$0.015000

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.012500	$0.007500	$0.002500
Next 3,000 kWh	$0.017500	$0.012500	$0.007500
3,501 kWh and above	$0.022500	$0.017500	$0.012500

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.005000	$0.000001
Next 3,000 kWh	$0.010000	$0.005000
3,501 kWh and above	$0.015000	$0.010000

Delivery (FOR OPTION CN ONLY):

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.015000	$0.010000	$0.005000
Next 3,000 kWh	$0.020000	$0.015000	$0.010000
3,501 kWh and above	$0.025000	$0.020000	$0.015000

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.012500	$0.007500	$0.002500
Next 3,000 kWh	$0.017500	$0.012500	$0.007500
3,501 kWh and above	$0.022500	$0.017500	$0.012500

Tucson Electric Power
The Energy People

Pricing Plans:
R-201A FROZEN,
R-201BN AND R-201CN
Special Residential Electric Service

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.005000	$0.000001
Next 3,000 kWh	$0.010000	$0.005000
3,501 kWh and above	$0.015000	$0.010000

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Fixed Must-Run	$0.001047 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

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FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Deleted: tariff

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Tucson Electric Power
The Energy People

Pricing Plan GS-10 FROZEN
General Service

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE
A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service $ 9.00 per month

Customer Charge, Three Phase service $16.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

—	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.025525	$0.020680
Next 54,500 kWh	$0.035525	$0.030680
55,000 kWh and above	$0.040525	$0.035680

Fixed Must- Run, all kWh $0.001016 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

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Tucson Electric Power
The Energy People

Pricing Plan GS-10 FROZEN
General Service

ADJUSTMENT FOR PRIMARY SERVICE AND METERING
The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$2.12 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.23 per month
Customer Delivery	$2.85 per month

Note: Additional meter service charge of $7.00 per month for Three Phase Service.

Energy Charges:

Delivery:

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.025525	$0.020680
Next 54,500 kWh	$0.035525	$0.030680
55,000 kWh and above	$0.040525	$0.035680

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003293 per kWh
System Benefits	$0.000443 per kWh
Transmission	$0.007298 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Fixed Must-Run	$0.001016 per kWh
Market Generation Charge ("MGC")	

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Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.¶
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The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

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DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

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FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

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Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Fuel and Purchased Power:

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.0	$0.0
Next 54,500 kWh	$0.0	$0.0
55,000 kWh and above	$0.0	$0.0

Tucson Electric Power
The Energy People

Pricing Plan GS-11 - FROZEN
Mobile Home Park Electric Service

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

To mobile home parks for service through a master meter to two or more mobile homes, provided each mobile home served through such master meter will be individually metered and billed by the park operator in accordance with applicable Orders of the Arizona Corporation Commission. Electric service to the park's facilities used by its residents may be supplied under this schedule only if such facilities are served through a master meter which serves two or more mobile homes.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service	$ 9.00 per month
Customer Charge, Three Phase service	$16.00 per month
Energy Charges:	
Summer (May – October, all kWh	$0.027156
Winter (November – April), all kWh	$0.017156
Fixed Must-Run, all kWh	$0.001016
Market Generation Charge ("MGC")	

The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

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Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.¶
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ADJUSTMENT FOR PRIMARY SERVICE AND METERING

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The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDL ED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$2.12 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.23 per month
Customer Delivery	$2.85 per month

Note: Additional meter service charge of $7.00 per month for Three Phase Service.

Energy Charges (kWh):

Delivery:

Summer (May – October), all kWh	$0.027156 per kWh
Winter (November – April), all kWh	$0.017156 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003293 per kWh
System Benefits	$0.000443 per kWh
Transmission	$0.007298 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Fuel Must-Run $0.001016 per kWh

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Market Generation Charge ("MGC")

The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

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DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

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FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

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Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Tucson Electric Power
The Energy People

Pricing Plan GS-31
Interruptible Agricultural Pumping

AVAILABILITY

Available for interruptible service to agricultural pumping customers throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

Applicable to separately metered interruptible agricultural water pumping service for irrigation purposes of the Customer only.

Not applicable to resale, breakdown, standby, auxiliary, or any other service except agricultural pumping in accordance with the provisions of this rate schedule.

CHARACTER OF SERVICE

Three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges:

Summer (May – October)	$0.004309 per kWh
Winter (November – April)	$0.004309 per kWh
Fixed Must-Run	$0.001016 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DETERMINATION OF HORSEPOWER FOR BILLING

Horsepower connected shall be the manufacturer's nameplate rating of all equipment of Customer connected for service under this schedule, but not less than 60 hp.

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MINIMUM BILL

The Customer guarantees that its load shall be sufficient such that a summation of all the above payments shall be not less than $30.00 per hp connected per contract year (which shall be from April 1 to March 31 of the following year) and in no event less than $1,800.00 per contract year. Minimum payments at the rate of $2.50 per hp of motors connected, but not less than $150.00 shall be made monthly.

If during the contract year the total payments exceed the annual guarantee of $30.00 per hp connected but not less than $1,800.00, then the Customer shall be credited the difference between the amount actually paid during the contract year and the amount which would have been paid had the monthly minimum charge not been applied.

TERMS AND CONDITIONS OF SERVICE

1. Customer must furnish, install, own, and maintain at each point of delivery all necessary Company approved equipment which will enable the Company to interrupt service with its master control station.
2. Service may be interrupted by Company during certain periods of the day not exceeding six hours in any 24-hour period.
3. Company will endeavor to give customer one hour notice of impending interruption; however, service may be interrupted without notice should Company deem such action necessary.
4. Where service other than agricultural pumping to which this rate is applicable has been taken hereunder, the general service rate shall be applied on a monthly basis to all usage billed hereunder during the previous twelve months less the aggregate of payments made hereunder for the same period of time. The general service rate shall continue to apply until the unauthorized service is permanently separated from the agricultural pumping service.
5. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy Charges:	
Delivery:	
Summer (May – October)	$0.004309 per kWh
Winter (November – April)	$0.004309 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003293 per kWh
System Benefits	$0.000443 per kWh
Transmission	$0.007298 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000099 per kWh

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Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Fixed Must-Run	$0.001016 per kWh

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Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS

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A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

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FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

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ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

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Tucson Electric Power
The Energy People

Pricing Plan GS-31
Interruptible Agricultural Pumping

The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancilary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4

Transmission Credit – Rider No. 5.

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Tucson Electric Power
The Energy People

Pricing Plan GS-76N
General Service Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service	$ 9.00 per month
Customer Charge, Three Phase service	$16.00 per month

Energy Charges:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.062389	$0.026579	$0.012889
Next 54,500 kWh	$0.072389	$0.036579	$0.022889
55,000 kWh and above	$0.077389	$0.041579	$0.027889

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.051360	$0.001860
Next 54,500 kWh	$0.061360	$0.011860
55,000 kWh and above	$0.066360	$0.016860

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak; there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

Fixed Must-Run, all kWhs $0.001016 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$2.12 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.23 per month
Customer Delivery	$2.85 per month

Note: Additional meter service charge of $7.00 per month for Three Phase Service.

Energy Charges:

Delivery:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.062389	$0.026519	$0.012889
Next 54,500 kWh	$0.072389	$0.036519	$0.022889
55,000 kWh and above	$0.077389	$0.041519	$0.027889

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.051360	$0.001860
Next 54,500 kWh	$0.061360	$0.011860
55,000 kWh and above	$0.066360	$0.016860

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003293 per kWh
System Benefits	$0.000443 per kWh
Transmission	$0.007298 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Fixed Must-Run	$0.001016 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

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FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

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Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Tucson Electric Power
The Energy People

Pricing Plan GS-85N
General Service Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge $371.88 per month

Demand Charges:
On-peak $3.00 per kW
Off-peak $1.00 per kW

Energy Charges:

	SUMMER (May – October)	WINTER (November – April)
On-peak, per kWh	$0.021062	$0.016380
Shoulder-peak, per kWh	$0.005146	N/A
Off-peak, per kWh	$0.000062	$0.012969

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak; there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

Fixed Must-Run, all kWhs $0.001016 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$223.13 per month
Meter Reading	$ 18.59 per month
Billing & Collection	$111.56 per month
Customer Delivery	$ 18.59 per month

Energy Charges:

Delivery:

On-peak	$3.00 per kW
Off-peak	$1.00 per kW

	SUMMER (May – October)	WINTER (November – April)
On-peak, per kWh	$0.021062	$0.016380
Shoulder-peak, per kWh	$0.005146	N/A
Off-peak, per kWh	$0.000062	$0.012969

Fixed Must-Run (See Must-Run Generation – Rider No. 2) $0.003293 per kWh

System Benefits $0.000443 per kWh

Transmission	$0.007298 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Fixed Must-Run	$0.001016 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

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FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

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Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Tucson Electric Power
The Energy People

Pricing Plan LLP-90N
Large Light and Power Service Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

CHARACTER OF SERVICE
Service shall be three phase, 60 Hertz, Primary Service, and shall be supplied directly from any 46,000 volt, or higher voltage, system at a delivery voltage of not less than 13,800 volts and delivered at a single point of delivery unless otherwise specified in the contract.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge — $500.00 per month

Demand Charges:
- On-peak — $8.00 per kW
- Off-peak — $2.66 per kW

Energy Charges:

	Summer (May – October)	Winter (November - April)
On-Peak	$0.019327	$0.016955
Shoulder-Peak	$0.028545	N/A
Off-Peak	$0.008425	$0.004455

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

_____On-Peak is 2:00 p.m. to 6:00 p.m.

_____Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

_____Off-Peak is 8:00 p.m. to 12:00 p.m.

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

_____On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

_____Shoulder-Peak; there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

Fixed Must-Run, all kWhs $0.000861 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

PRIMARY SERVICE
The above rate is subject to Primary Service and Metering. The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers

POWER FACTOR ADJUSTMENT
The above rate is subject to a discount or a charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is above or below 90% lagging to a maximum discount of 13.0¢ per kW of billing demand per month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

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Customer Charges:

Meter Services	$300.00 per month
Meter Reading	$25.00 per month
Billing & Collection	$150.00 per month
Customer Delivery	$25.00 per month

Energy Charges:

Delivery:

On-peak	$8.00 per kW
Off-peak	$2.66 per kW

	Summer (May – October)	Winter (November - April)
On-Peak, per kWh	$0.019327	$0.016955
Shoulder-Peak, per kWh	$0.008425	N/A
Off-Peak, per kWh	$0.028545	$0.004455

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Fixed Must-Run (See Must-Run Generation – Rider No. 2) $0.003408 per kWh

System Benefits	$0.000433 per kWh
Transmission	$0.006184 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000084 per kWh
Reactive Supply and Voltage Control	$0.000330 per kWh
Regulation and Frequency Response	$0.000320 per kWh
Spinning Reserve Service	$0.000867 per kWh
Supplemental Reserve Service	$0.000141 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Fixed Must-Run	$0.000861 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

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FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan;

Adder Associated with Market Generation Credit – Rider No. 1

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Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Tucson Electric Power
The Energy People

Pricing Plan PS-40
Municipal Service

AVAILABILITY

Available for Municipal Service where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

Applicable for service to the City of Tucson and City of South Tucson for Municipal buildings and grounds.

Not applicable to resale, breakdown, standby, or auxiliary service or to buildings used for residential purposes.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, at secondary voltage and subject to availability at point of delivery approved by the Company.

RATE

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges:

Summer (May – October, all kWh	$0.048952
Winter (November – April), all kWh	$0.038952

Fixed Must-Run, all kWhs	$0.000853

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy Charges:
Delivery:

Summer (May – October, all kWh	$0.048952
Winter (November – April), all kWh	$0.038952
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003289 per kWh

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System Benefits	$0.000434 per kWh
Transmission	$0.006129 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000083 per kWh
Reactive Supply and Voltage Control	$0.000327 per kWh
Regulation and Frequency Response	$0.000317 per kWh
Spinning Reserve Service	$0.000860 per kWh
Supplemental Reserve Service	$0.000140 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Fixed Must-Run	$0.000853 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

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DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

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FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

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ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

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The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

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Tucson Electric Power
The Energy People

Pricing Plan PS-41
Traffic Signal and Street Lighting Service

AVAILABILITY
Available for service to the State, a county, city, town, political subdivision, improvement district, or a responsible person or persons for unincorporated communities for Traffic Signal and Street Lighting purposes where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Applicable to Customer owned and maintained traffic signals and public street and highway lighting.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery approved by the Company.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

All kWh @ $0.050196 per kWh

Fixed Must-Run, all kWh _____ $0.000661 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Delivery	$0.019894 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.002305 per kWh
System Benefits	$0.000413 per kWh
Transmission	$0.026736 per kWh
Transmission Ancillary Services	

System Control & Dispatch	$0.000363 per kWh
Reactive Supply and Voltage Control	$0.001427 per kWh
Regulation and Frequency Response	$0.001383 per kWh
Spinning Reserve Service	$0.003750 per kWh
Supplemental Reserve Service	$0.000612 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Fixed Must-Run, all kWh ..... $0.000661 per kWh

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Market Generation Credit ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

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FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Tucson Electric Power
The Energy People

Pricing Plan PS-43
Municipal Water Pumping Service

AVAILABILITY
Available for service to the City of Tucson Water Utility and private water Companies where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Applicable for service to booster stations and wells used for domestic water supply.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as elected by Customer and subject to availability at point of delivery approved by the Company. Primary metering may be used by mutual agreement.

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges Firm Service:

Summer (May – October), all kWh	$0.081989
Winter (November – April), all kWh	$0.071989

Energy Charges Interruptible Service:

Summer (May – October), all kWh	$0.066989
Winter (November – April), all kWh	$0.065989

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Fixed Must-Run, all kWh	$0.000853

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy Charges:
Delivery Firm Service:

Summer (May – October), all kWh	$0.081989
Winter (November – April), all kWh	$0.071989

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Delivery Interruptible Service:

Summer (May – October), all kWh	$0.066989
Winter (November – April), all kWh	$0.065989

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003289 per kWh
System Benefits	$0.000434 per kWh
Transmission	$0.006129 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000083 per kWh
Reactive Supply and Voltage Control	$0.000327 per kWh
Regulation and Frequency Response	$0.000317 per kWh
Spinning Reserve Service	$0.000860 per kWh
Supplemental Reserve Service	$0.000140 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Fixed Must-Run $0.000853 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

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A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.¶ ... [1]

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TERMS AND CONDITIONS OF INTERRUPTIBLE SERVICE

1. Customer must furnish, install, own, and maintain at each point of delivery all necessary Company approved equipment which will enable the Company to interrupt service with its master control station.

2. Service may be interrupted by Company during certain periods of the day not exceeding six hours in any 24-hour period.

3. Company will endeavor to give Customer one hour notice of impending interruption; however, service may be interrupted without notice should Company deem such action necessary.

4. The interruptible load shall be separately served and metered and shall at no time be connected to facilities serving Customer's firm load. Conversely, the firm load shall be separately served and metered and shall at no time be connected to facilities serving Customer's interruptible load.

5. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

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tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

Tucson Electric Power
The Energy People

Pricing Plan PS-50
Public Street Lighting Service

AVAILABILITY
Available for service for lighting public streets, alleys, thoroughfares, public parks, and playgrounds by use of Company's standard facilities where such service is contracted under this pricing plan by the state, a county, city, town, political subdivision, improvement district, or a responsible person or persons for unincorporated communities.

APPLICABILITY
Applicable to street lighting service from dusk to dawn and Company will own, operate, and maintain the street light system including lamps and globe replacements.

CHARACTER OF SERVICE
Multiple or series street lighting system at option of Company and at one standard nominal voltage.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
per unit per month	$10.39	$10.39	$10.39	$15.60	$24.06	$19.68	$3.63

Note:

The watt high pressure sodium lamps are charged per unit per month.

Per one pole addition and an extension of up to 100 feet of overhead service are charged per pole.

Underground Service is per 100 watt or less high pressure sodium lamp unit per month mounted on standard pole.

Fixed Must-Run, all kWh $0.000661 per kWh

Market Generation Charge ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

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STANDARD LAMP UNITS, OVERHEAD SERVICE

(1) The standard 100 watt lamp unit for overhead service is a 9,500 lumen high pressure sodium unit, mounted on a four foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 25 feet above ground level.

(2) The standard 250 watt lamp unit for overhead service is a 27,500 lumen high pressure sodium unit, mounted on an eight foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 27 feet above ground level.

(3) The standard 400 watt lamp unit for overhead service is a 50,000 lumen high pressure sodium unit, mounted on an eighteen foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 35 feet above ground level.

(4) The standard 100 watt lamp unit for underground service is a 9,500 lumen high pressure sodium post top unit mounted on a pole approximately 15 feet above ground level.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Delivery	$9.75	$9.59	$9.25	$12.79	$19.59
Fixed Must-Run	$0.04	$0.05	$0.07	$0.17	$0.28
System Benefits	$0.01	$0.01	$0.01	$0.03	$0.05
Transmission	$0.44	$0.56	$0.80	$2.01	$3.21
Transmission Ancillary					
System Control & Load Dispatch	$0.01	$0.01	$0.01	$0.03	$0.04
Reactive Supply and Voltage Control	$0.02	$0.03	$0.04	$0.11	$0.17
Regulation and Frequency Response	$0.02	$0.03	$0.04	$0.10	$0.17
Spinning Reserve Service	$0.06	$0.08	$0.11	$0.28	$0.45
Supplemental Reserve Service	$0.01	$0.01	$0.02	$0.05	$0.07
Energy Imbalance Service: currently charged pursuant to the Company's OATT.					
Fixed Must-Run	$0.01	$.01	$0.02	$0.05	$0.08

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DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

SPECIAL PROVISIONS

(1) Installation of a light on an existing pole is subject to prior approval of Company.

(2) For underground service, where customer provides trenching up to 10 feet in accordance with Company's electric service requirements, customer shall be billed at the rates for overhead service.

(3) Extensions beyond 100 feet and all installations other than those addressed in this pricing plan will require specific agreements providing adequate revenue or arrangements for construction financing.

(4) The Customer is not authorized to make connections to this lighting circuit or to make attachments or alterations to the Company owned pole.

(5) If a Customer requests a relocation of a lighting installation, the costs of such relocation must be borne by the Customer.

(6) The Customer is expected to notify the Company when lamp outages occur.

(7) The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

(8) After the minimum contract period, if any, has expired, this agreement shall be extended from year to year unless written notice of desire to terminate is given by either party at least thirty (30) days prior to the end of any such annual extension date.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan. Any condition not provided for herein must be the subject of a separate written agreement.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan GS-51
Private Street and Area Lighting Service

AVAILABILITY
At any point where the Company in its judgment has facilities of adequate capacity and suitable voltage available.

APPLICABILITY
To any Customer for private street or outdoor area lighting where this service can be supplied from existing facilities of the Company.

Service is from dusk to dawn and the Company will install, own, operate, and maintain the complete lighting installation including lamp replacements.

Not applicable to resale service.

CHARACTER OF SERVICE
Multiple or series street lighting system at option of Company and at one standard nominal voltage.

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
per unit per month	$10.39	$10.39	$10.39	$15.60	$24.06	$19.68	$3.63

Note:

The watt high pressure sodium lamps are charged per unit per month.

Per one pole addition and an extension of up to 100 feet of overhead service are charged per pole.

Underground Service is per 100 watt or less high pressure sodium lamp unit per month mounted on standard pole.

Fixed Must-Run, all kWh $0.000661 per kWh

Market Generation Credit ("MGC")
The market generation credit represents the cost of fuel and purchased power. The rate will be calculated monthly for inclusion in customers' bills. See Schedule MGC -1 for information regarding the components and the calculation of the MGC.

STANDARD LAMP UNITS, OVERHEAD SERVICE

(1) The standard 100 watt lamp unit for overhead service is a 9,500 lumen high pressure sodium unit, mounted on a four foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 25 feet above ground level.

(2) The standard 250 watt lamp unit for overhead service is a 27,500 lumen high pressure sodium unit, mounted on an eight foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 27 feet above ground level.

(3) The standard 400 watt lamp unit for overhead service is a 50,000 lumen high pressure sodium unit, mounted on an eighteen foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 35 feet above ground level.

(4) The standard 100 watt lamp unit for underground service is a 9,500 lumen high pressure sodium post top unit mounted on a pole approximately 15 feet above ground level.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Delivery	$9.75	$9.59	$9.25	$12.79	$19.59
Fixed Must-Run	$0.04	$0.05	$0.07	$0.17	$0.28
System Benefits	$0.01	$0.01	$0.01	$0.03	$0.05
Transmission	$0.44	$0.56	$0.80	$2.01	$3.21
Transmission Ancillary					
System Control & Load Dispatch	$0.01	$0.01	$0.01	$0.03	$0.04
Reactive Supply and Voltage Control	$0.02	$0.03	$0.04	$0.11	$0.17
Regulation and Frequency Response	$0.02	$0.03	$0.04	$0.10	$0.17
Spinning Reserve Service	$0.06	$0.08	$0.11	$0.28	$0.45
Supplemental Reserve Service	$0.01	$0.01	$0.02	$0.05	$0.07
Energy Imbalance Service: currently charged pursuant to the Company's OATT.					
Fixed Must-Run	$0.01	$.01	$0.02	$0.05	$0.08

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

SPECIAL PROVISIONS

(1) Installation of a light on an existing pole is subject to prior approval of Company.

(2) For underground service, where customer provides trenching up to 10 feet in accordance with Company's electric service requirements, customer shall be billed at the rates for overhead service.

(3) Extensions beyond 100 feet and all installations other than those addressed in this pricing plan will require specific agreements providing adequate revenue or arrangements for construction financing.

(4) The Customer is not authorized to make connections to this lighting circuit or to make attachments or alterations to the Company owned pole.

(5) If a Customer requests a relocation of a lighting installation, the costs of such relocation must be borne by the Customer.

(6) The Customer is expected to notify the Company when lamp outages occur.

(7) The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

(8) After the minimum contract period, if any, has expired, this agreement shall be extended from year to year unless written notice of desire to terminate is given by either party at least thirty (30) days prior to the end of any such annual extension date.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan. Any condition not provided for herein must be the subject of a separate written agreement.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Adder Associated with Market Generation Credit – Rider No. 1

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Tucson Electric Power
The Energy People

Rider 1
Adder Associated with Market Generation Credit

All prices in mills per kWh

	Mills per kWh
All customers up to 200 kW demand	
Summer kWh up to 115% of winter kWh	3.84
Summer kWh greater than 115% but less than or equal to 145% of winter kWh	4.44
Summer kWh greater than 145% but less than or equal to 175% of winter kWh	5.04
Summer kWh greater than 175% but less than or equal to 205% of winter kWh	5.64
Summer kWh greater than 205% of winter kWh	6.24
All customers from 200 kW to 3000 kW demand	
Summer kWh up to 106% of winter kWh	3.00
Summer kWh greater than 106% but less than or equal to 136% of winter kWh	3.48
Summer kWh greater than 136%	3.96
All customers 3000 kW demand and above	
Air Liquide	3.00
Fort Huachuca	3.00
Arizona Portland Cement	3.00
IBM	3.00
Asarco Mission 1	3.00
Asarco Mission 2	3.00
Asarco Silverbell	3.00
Cyprus	3.00
University of Arizona Main Campus	3.00
University of Arizona Health Sciences Center	3.00
University of Arizona Central Heating & Refrigeration Plant	3.00
Burr Brown	3.00
Davis Monthan Air Force Base	3.00
Raytheon	3.00
University Medical Center	3.00
Tucson Medical Center	3.00

EXHIBIT

DBE-3

CLEAN VERSION

Pricing Plan R-01 FROZEN
Residential Electric Service

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single phase or three phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter; however, electric water heating may be metered separately.

Not applicable to resale, breakdown, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, nominal 120/240 volts.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service $ 9.00 per month

Customer Charge, Three Phase service $15.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.048208	$0.043208
Next 3,000 kWh	$0.058208	$0.053208
3,501 kWh and above	$0.063208	$0.058208

Generation Capacity, all kWh $0.000322 per kWh

Fuel and Purchased Power:

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.027684	$0.022684
Next 3,000 kWh	$0.037684	$0.032684
3,501 kWh and above	$0.042684	$0.037684

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.51 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.29 per month
Customer Delivery	$3.40 per month

Note: Additional meter service charge of $6.00 per month for Three Phase Service.

Energy (kWh) and Demand Charges (kW):

Delivery

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.034246	$0.029246
Next 3,000 kWh	$0.044246	$0.039246
3,501 kWh and above	$0.049246	$0.044246

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000322 per kWh

Fuel and Purchased Power

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.027684	$0.022684
Next 3,000 kWh	$0.037684	$0.032684
3,501 kWh and above	$0.042684	$0.037684

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan R-02 FROZEN
Residential Electric Water Heating Service

AVAILABILITY
This rate is limited to installations and customers served under Pricing Plan No. 2 on the effective date of this tariff sheet.

APPLICABILITY
To separately metered single phase residential off-peak water heating service where general residential service is also provided under Pricing Plan No. 1. When service under Pricing Plan No. 2 is discontinued, the Company will either combine usage and bill under Pricing Plan No. 1 or modify the service entrance equipment so all service is supplied through the Pricing Plan No. 1 meter.

Not applicable to three phase service, resale, breakdown, standby, auxiliary, or any other service except off-peak water heating in accordance with the provisions of this pricing plan.

Where service other than water heating to which this rate is applicable has been taken hereunder, the regular rate for such service shall be applied on a monthly basis to all consumption billed hereunder during the previous twelve months, less the aggregate of payments made hereunder for the same period of time. The regular rate shall continue to apply until the unauthorized service is permanently separated from the off-peak water heating service.

CHARACTER OF SERVICE
Single phase, 60 Hertz, nominal 120/240 volts.

Service may be controlled by the Company by disconnecting electricity during certain periods of the day not exceeding 8 hours in any 24-hour period, as determined by the Company from time to time.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges:

Delivery, all kWh	$0.050000 per kWh
Generation Capacity, all kWh	$0.000322 per kWh
Fuel and Purchased Power, all kWh	$0.034570 per kWh

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy:

Delivery	$0.036038 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity	$0.000322 per kWh
Fuel and Purchased Power	$0.034570 per kWh

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

The electric water heating equipment and installation shall conform to the Company's requirements and be for normal domestic use. The heater shall be of the storage type and not less than 30-gallon capacity. For a water heater equipped with one heating element, the rating of the heating element shall not exceed 6,000 watts. For a water heater equipped with more than one heating element, the rating of any such heating element shall not exceed 6,000 watts, and, if the total of the ratings of the elements exceeds 6,000 watts, they shall be thermostatically interlocked so that they cannot operate simultaneously and thereby exceed 6,000 watts. The Customer shall provide the necessary wiring to permit the installation of the Company's metering and control equipment.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan R-21 - ELIMINATED
Residential Time-of-Use

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises. Direct access to the meter during normal working hours is also a prerequisite for this rate schedule.

APPLICABILITY

To any Customer entitled to single phase service under Rate 01. Preference may be given to those Customers whose historic or expected annual usage exceeds 16,000 kWh. Service must be single phase residential electric service in individual private dwellings and individually metered multi-family units when all service is supplied at one point of delivery and energy is metered through one meter; however, controlled off-peak electric water heating may be metered separately.

Not applicable to three phase service, resale, breakdown, temporary, standby, or auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

The total number of Customers served under this Time-of-Use Rate Schedule is limited to 5,000. Service under this schedule will commence when the appropriate meter has been installed.* Customers must stay on this Rate Schedule for a minimum period of one (1) year.

The waiting list for service under this Time-of-Use Rate Schedule was frozen as of March 31, 1996.

As meters become available from the original group of 5,000, customers on the frozen waiting list will be offered service under this Rate Schedule in the order that they were placed on the waiting list.

Customers currently served under this Rate Schedule that change residences will *not* be allowed to receive service under this Rate Schedule at their new residence.

CHARACTER OF SERVICE

Single phase, 60 Hertz, nominal 120/240 volts.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this rate schedule:

	BILLING MONTHS	
	Summer May-Oct.	Winter Nov.-Apr.
Customer Charge per month	$6.86	$6.86
On-Peak kWh per month	$0.125413	$0.099018
Off-Peak kWh per month	$0.050165	$0.050165
Minimum Bill per month	$6.86	$6.86

During the summer season, the On-Peak period is 10:00 a.m. to 10:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). During the winter season, the On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day). All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

Service Connection Charges

1. There shall be a $13.50 charge for the initial establishment of each new service for each Customer.

2. There shall be a $13.50 charge for the re-establishment of each service for each Customer.

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this rate schedule.

Optional rates are or may become available for certain classes of Customers. Upon application for service or upon request the Company will assist the Customer in selecting the rate schedule best suited to the Customer's requirements, but Company does not guarantee that Customers will be served under the most favorable rate schedule. Upon written notification of any material changes in Customer's installation, load conditions, or use of service, Company will assist in determining if a change in rates is desirable, but not more than one such change in rates will be made within any twelve month period.

Electric space heating and water heating equipment and installation shall conform to the Company's requirements.

*This Rate Schedule requires a type of meter that is not normally used; therefore, the Company makes no guarantee that meters will be installed within any specific time. However, the Company will make its best effort to install the special meter within a reasonable time.

The summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day). All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

Service Connection Charges

1. There shall be a $13.50 charge for the initial establishment of each new service for each Customer.
2. There shall be a $13.50 charge for the re-establishment of each service for each Customer.

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this rate schedule.

Optional rates are or may become available for certain classes of Customers. Upon application for service or upon request the Company will assist the Customer in selecting the rate schedule best suited to the Customer's requirements, but Company does not guarantee that Customers will be served under the most favorable rate schedule. Upon written notification of any material changes in Customer's installation, load conditions, or use of service, Company will assist in determining if a change in rates is desirable, but not more than one such change in rates will be made within any twelve month period.

Electric space heating and water heating equipment and installation shall conform to the Company's requirements.

*This Rate Schedule requires a type of meter that is not normally used; therefore, the Company makes no guarantee that meters will be installed within any specific time. However, the Company will make its best effort to install the special meter within a reasonable time.

Pricing Plan R-70 - ELIMINATED
Residential Time-of-Use

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises. Direct access to the meter during normal working hours is also a prerequisite for this rate schedule.

APPLICABILITY

To any Customer entitled to single phase service under Rate No. 01. Service is available to individual private dwellings and individually metered multi-family units when all service is supplied at one point of delivery and energy is metered through one meter; however, controlled off-peak electric water heating may be metered separately.

Not applicable to three phase service, resale, breakdown, temporary, standby, or auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

Service under this schedule will commence when the appropriate meter has been installed.* Customers must stay on this Rate Schedule for a minimum period of one (1) year. A Customer, at his/her discretion and after being served for a twelve (12) month period under Rate No. 70, may opt to switch service to the Company's non-time-of-use Residential Rate No. 1. The Company shall refund to the Customer any excess moneys paid in total over the entire twelve months under Rate No. 70 that would not have been paid under Rate No. 1. A Customer shall be eligible to receive such a refund of excess moneys on a single occasion only.

CHARACTER OF SERVICE

Single phase, 60 Hertz, nominal 120/240 volts.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this rate schedule:

	Billing Months	
	Summer May-Oct.	Winter Nov.-Apr.
Customer Charge	$6.78	$6.78
On-Peak kWh @	$0.184171	$0.126011
Shoulder kWh @	$0.116318	N/A
Off-Peak kWh @	$0.058160	$0.043619
Minimum Bill per month	$6.78	$6.78

The Company has the option to price service in the billing months of May and October at lower levels, which levels shall not be less than marginal cost. Any shoulder consumption remaining from October usage will be billed at the summer shoulder rate in following billing months.

Pricing Plan R-70N
Residential Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Service is available to individual private dwellings and individually metered multi-family units when all service is supplied at one point of delivery and energy is metered through one meter; however, controlled off-peak electric water heating may be metered separately.

Not applicable to three phase service, resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

Service under this pricing plan will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
Single phase, 60 Hertz, nominal 120/240 volts.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge: $9.00 per month

Energy Charges:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.083474	$0.049169	$0.033974
Next 3,000 kWh	$0.093474	$0.059169	$0.043974
3,501 kWh and above	$0.098474	$0.064169	$0.048974

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.071135	$0.021635
Next 3,000 kWh	$0.081135	$0.031635
3,501 kWh and above	$0.086135	$0.036635

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak: there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

If a Summer or Winter holiday falls on Saturday, the preceding Friday is designated off-peak; if a holiday falls on Sunday, the following Monday is designated off-peak.

Energy Charges continued:

Generation Capacity $0.000322 per kWh

Fuel and Purchased Power:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.062950	$0.028645	$0.013450
Next 3,000 kWh	$0.072950	$0.038645	$0.023450
3,501 kWh and above	$0.077950	$0.043645	$0.028450

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.050611	$0.001111
Next 3,000 kWh	$0.060611	$0.011111
3,501 kWh and above	$0.065611	$0.016111

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.51 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.29 per month
Customer Delivery	$3.40 per month

Energy (kWh):

Delivery

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.069512	$0.035207	$0.020012
Next 3,000 kWh	$0.079512	$0.045207	$0.030012
3,501 kWh and above	$0.084512	$0.050207	$0.035012

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.057173	$0.007673
Next 3,000 kWh	$0.067173	$0.017673
3,501 kWhs and above	$0.072173	$0.022673

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Generation Capacity	$0.000322 per kWh

Fuel and Purchased Power:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.062950	$0.028645	$0.013450
Next 3,000 kWh	$0.072950	$0.038645	$0.023450
3,501 kWh and above	$0.077950	$0.043645	$0.028450

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.050611	$0.001111
Next 3,000 kWh	$0.060611	$0.011111
3,501 kWh and above	$0.065611	$0.016111

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan R-201 - ELIMINATED
Special Residential Electric Service

AVAILABILITY

In all territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served. Access to the meter during normal working hours is also a prerequisite for Options B & C of this Schedule.

APPLICABILITY

To single phase or three phase (Option A only) (subject to availability at point of delivery) electric service in individual residences as described in current program details when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this Schedule requires that the customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below and that the customer's home conform to the standards of the Heating, Cooling and Comfort Guarantee program as in effect at the time of subscription to this Schedule. Notwithstanding the above, the customer's use of solar energy for any purpose shall not preclude subscription to this Schedule. Three different Options are available under this Schedule: A, B, & C. Subscription eligibility requirements are as follows:

Option A: Customer must meet conditions outlined above;

Option B: Customer must meet conditions required for option A and must purchase under the time-of-use structure applicable to Option B. Applicable only to single phase service.

Option C: Customer must meet above conditions required for option A, must use either (i.) solar equipment for water heating requirements during the year or (ii.) an electric heat pump water heater, or both (i.) and (ii.), and must purchase under the time-of-use structure applicable to Option C. Applicable only to single phase service.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

Service under Option B or Option C of this Schedule will commence when the appropriate meter has been installed.* Customers must stay on Option B or Option C of this Schedule for a minimum period of one (1) year. A Customer, at his/her discretion and after being served for a twelve (12) month period under Option B or Option C of this Schedule, may opt to switch service to the non-time-of-use Option A of this Schedule. The Company shall refund to the Customer any excess moneys paid in total over the entire twelve months under Rate No. 201, Option B or Option C that would not have been paid under Rate No. 201A. A Customer shall be eligible to receive such a refund of excess moneys on a single occasion only.

CHARACTER OF SERVICE

Single or three phase (Option A only), 60 Hertz, nominal 120/240 volts.

PRICE UNDER OPTION A

Monthly net bills shall reflect the following prices plus any adjustments incorporated in this Schedule:

Single Phase Service	
Customer Charge per month	$4.90
All kWh consumed in mid-summer season of June 1 - August 31 @	$0.090920
All kWh consumed in remaining summer season of May 1 - May 31 & September 1 - October 31 @	$0.074191
All kWh consumed in winter season of November 1 - April 30 @	$0.064440

Three Phase Service
Same as Single Phase Service, except a three phase additional charge of $7.36 per month shall apply to Customers receiving three phase service.

Minimum Bill
$4.90 for Single Phase Service
$12.26 for Three Phase Service

PRICE UNDER OPTION B
Monthly net bills shall reflect the following prices plus any adjustments incorporated in this Schedule:

	CONSUMPTION MONTHS		
	Mid-Summer Jun.-Aug.	Remaining Summer May & Sept.-Oct.	Winter Nov.-Apr.
Customer Charge	$6.78	$6.78	$6.78
On-Peak kWh @	$0.184171	$0.146415	$0.100179
Shoulder kWh @	$0.116318	$0.092473	N/A
Off-Peak kWh @	$0.058160	$0.046236	$0.034673
Minimum Bill per month	$6.78	$6.78	$6.78

The Company has the option to price service in the billing months of May and October at lower levels, which levels shall not be less than marginal cost. Any shoulder consumption remaining from October usage will be billed at the shoulder summer shoulder price in following billing months.

The summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day). All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

PRICE UNDER OPTION C
Monthly net bills shall reflect the following prices plus any adjustments incorporated in this Schedule:

	CONSUMPTION MONTHS		
	Mid-Summer Jun.-Aug.	Remaining Summer May & Sept.-Oct.	Winter Nov.-Apr.
Customer Charge	$6.78	$6.78	$6.78
On-Peak kWh @	$0.184171	$0.137207	$0.093879
Shoulder kWh @	$0.116318	$0.086658	N/A
Off-Peak kWh @	$0.058160	$0.043328	$0.032491
Minimum Bill per month	$6.78	$6.78	$6.78

The Company has the option to price service in the billing months of May and October at lower levels, which levels shall not be less than marginal cost. Any shoulder consumption remaining from October usage will be billed at the shoulder summer shoulder price in following billing months.

The summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day). All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

TAX CLAUSE

To the charges computed under the above prices, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

Service Connection Charges

1. There shall be a $13.50 charge for the initial establishment of each new service for each Customer.

2. There shall be a $13.50 charge for the re-establishment of each service for each Customer.

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this Schedule.

Optional price schedules are or may become available for certain classes of Customers. Upon application for service or upon request the Company will assist the Customer in selecting the price schedule best suited to the Customer's requirements, but Company does not guarantee that Customers will be served under the most favorable schedule. Upon written notification of any material changes in Customer's installation, load conditions, or use of service, the Company shall assist in determining if a change in schedule is desirable, but not more than one such change shall be made within any twelve month period.

Electric space heating and water heating equipment and installation shall conform to the Company's requirements.

*This Schedule requires a type of meter not normally used; therefore, the Company makes no guarantee that the meters will be installed within any specific time. However, the Company will make its best effort to install the special meter within a reasonable time.

Pricing Plans:
R-201A FROZEN,
R-201BN AND R-201CN
Special Residential Electric Service

AVAILABILITY
Throughout the entire area where facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To single phase electric service in individual residences as described in current program details when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this Schedule requires that the customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below and that the customer's home conform to the standards of the Heating, Cooling and Comfort Guarantee program as in effect at the time of subscription to this Schedule. Notwithstanding the above, the customer's use of solar energy for any purpose shall not preclude subscription to this Schedule. Two different Options are available under this Schedule: BN, & CN. Subscription eligibility requirements are as follows:

Option A: This option is FROZEN to new customers.
Option BN: Customer must meet above conditions and must purchase under the time-of-use structure.
Option CN: Customer must meet above conditions and must use either (i.) solar equipment for water heating requirements during the year or (ii.) an electric heat pump water heater, or both (i.) and (ii.), and must purchase under the time-of-use structure applicable to Option CN.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
Single phase, 60 Hertz, nominal 120/240 volts.

PRICE UNDER OPTION A
A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Minimum Customer Charge $ 9.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.049000	$0.044000	$0.041500
Next 3,000 kWh	$0.059000	$0.054000	$0.051500
3,501 kWh and above	$0.064000	$0.059000	$0.056500

Generation Capacity, all kWh $0.000322 per kWh

Fuel and Purchase Power:

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.021076	$0.016076	$0.013576
Next 3,000 kWh	$0.031076	$0.026076	$0.023576
3,501 kWh and above	$0.036076	$0.031076	$0.028576

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

PRICE UNDER OPTION BN

A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Minimum Customer Charge $ 9.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.051000	$0.041000	$0.036000
Next 3,000 kWh	$0.061000	$0.051000	$0.046000
3,501 kWh and above	$0.056000	$0.046000	$0.041000

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.046000	$0.036000	$0.031000
Next 3,000 kWh	$0.056000	$0.046000	$0.041000
3,501 kWh and above	$0.051000	$0.041000	$0.036000

The Mid-Summer and Remaining Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day:

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.
Off-Peak is 8:00 p.m. to 12:00 p.m.
On-Peak is 2:00 p.m. to 6:00 p.m.

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.043500	$0.038500
Next 3,000 kWh	$0.053500	$0.048500
3,501 kWh and above	$0.048500	$0.043500

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day:

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: there are no shoulder peak periods in the winter.
Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

If a Summer or Winter holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

Energy Charges continued:

Generation Capacity $0.000322 per kWh

Fuel and Purchased Power:

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.028076	$0.018076	$0.013076
Next 3,000 kWh	$0.038076	$0.028076	$0.023076
3,501 kWh and above	$0.033076	$0.023076	$0.018076

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.023076	$0.013076	$0.008076
Next 3,000 kWh	$0.033076	$0.023076	$0.018076
3,501 kWh and above	$0.028076	$0.018076	$0.013076

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.020576	$0.015576
Next 3,000 kWh	$0.030576	$0.025576
3,501 kWh and above	$0.025576	$0.020576

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchase Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

PRICE UNDER OPTION CN

A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Minimum Customer Charge $ 9.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.049980	$0.040180	$0.035280
Next 3,000 kWh	$0.059780	$0.049980	$0.045080
3,501 kWh and above	$0.054880	$0.045080	$0.040180

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.045080	$0.035280	$0.030380
Next 3,000 kWh	$0.054880	$0.045080	$0.040180
3,501 kWh and above	$0.049980	$0.040180	$0.035280

The Mid-Summer and Remaining Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day:

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.
Off-Peak is 8:00 p.m. to 12:00 p.m.
On-Peak is 2:00 p.m. to 6:00 p.m.

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.042630	$0.037730
Next 3,000 kWh	$0.052430	$0.047530
3,501 kWh and above	$0.047530	$0.042630

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day:

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: there are no shoulder peak periods in the winter.
Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

If a Summer or Winter holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

Energy Charges continued:

Generation Capacity $0.000322 per kWh

Fuel and Purchase Power:

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.026734	$0.016934	$0.012034
Next 3,000 kWh	$0.036534	$0.026734	$0.021834
3,501 kWh and above	$0.031634	$0.021834	$0.016934

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.021834	$0.012034	$0.007134
Next 3,000 kWh	$0.031634	$0.021834	$0.016934
3,501 kWh and above	$0.026734	$0.016934	$0.012034

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.019384	$0.014484
Next 3,000 kWh	$0.029184	$0.024284
3,501 kWh and above	$0.024284	$0.019384

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchase Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE R-201A FROZEN, R-201BN AND R201CN CONSIST OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.51 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.29 per month
Customer Delivery	$3.40 per month

Note: Additional meter service charge of $6.00 per month for Three Phase Service.

Pricing Plans: R-201A FROZEN, R-201BN AND R-201CN Special Residential Electric Service

Energy:

Delivery **(FOR OPTION A ONLY):**

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.035038	$0.030038	$0.027538
Next 3,000 kWh	$0.045038	$0.040038	$0.037538
3,501 kWh and above	$0.050038	$0.045038	$0.042538

Delivery **(FOR OPTION BN ONLY):**

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.037038	$0.027038	$0.022038
Next 3,000 kWh	$0.047038	$0.037038	$0.032038
3,501 kWh and above	$0.042038	$0.032038	$0.027038

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.032038	$0.022038	$0.017038
Next 3,000 kWh	$0.042038	$0.032038	$0.027038
3,501 kWh and above	$0.037038	$0.027038	$0.022038

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.029538	$0.024538
Next 3,000 kWh	$0.039538	$0.034538
3,501 kWh and above	$0.034538	$0.029538

Delivery **(FOR OPTION CN ONLY):**

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.036018	$0.026218	$0.021318
Next 3,000 kWh	$0.045818	$0.036018	$0.031118
3,501 kWh and above	$0.040918	$0.031118	$0.026218

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.031118	$0.021318	$0.016418
Next 3,000 kWh	$0.040918	$0.031118	$0.026218
3,501 kWh and above	$0.036018	$0.026218	$0.021318

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.028668	$0.023768
Next 3,000 kWh	$0.038468	$0.033568
3,501 kWh and above	$0.033568	$0.028668

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Generation Capacity	$0.000322 per kWh

Fuel and Purchased Power:

(FOR OPTION A ONLY):

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.021076	$0.016076	$0.013576
Next 3,000 kWh	$0.031076	$0.026076	$0.023576
3,501 kWh and above	$0.036076	$0.031076	$0.028576

(FOR OPTION BN ONLY):

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.028076	$0.018076	$0.013076
Next 3,000 kWh	$0.038076	$0.028076	$0.023076
3,501 kWh and above	$0.033076	$0.023076	$0.018076

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.023076	$0.013076	$0.008076
Next 3,000 kWh	$0.033076	$0.023076	$0.018076
3,501 kWh and above	$0.028076	$0.018076	$0.013076

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.020576	$0.015576
Next 3,000 kWh	$0.030576	$0.025576
3,501 kWh and above	$0.025576	$0.020576

(FOR OPTION CN ONLY):

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.026734	$0.016934	$0.012034
Next 3,000 kWh	$0.036534	$0.026734	$0.021834
3,501 kWh and above	$0.031634	$0.021834	$0.016934

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.021834	$0.012034	$0.007134
Next 3,000 kWh	$0.031634	$0.021834	$0.016934
3,501 kWh and above	$0.026734	$0.016934	$0.012034

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.019384	$0.014484
Next 3,000 kWh	$0.029184	$0.024284
3,501 kWh and above	$0.024284	$0.019384

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan R-06
Residential Lifeline Discount

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To electric service qualifying for billing under an approved and available Residential Pricing Plan where the customer also has qualified for Rate No. 5 as specified in the Company's plan for administration. All provisions of the Company's residential pricing plan chosen for service will apply except as modified herein. This discount is also available to tenants of master metered mobile home parks and apartments.

MONTHLY BILL
The monthly bill shall be in accordance with an applicable Residential Pricing Plan except that a discount of $8.00 per month shall be applied. This notwithstanding, the minimum monthly bill shall be zero. That is, the $8.00 monthly discount cannot be used to create a negative monthly bill (i.e., when the monthly bill before the discount is less than $8.00, and an $8.00 discount would otherwise create a bill credit for the month).

Pricing Plan GS-10 FROZEN
General Service

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE
A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service $ 9.00 per month

Customer Charge, Three Phase service $16.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.061455	$0.056455
Next 54,500 kWh	$0.071455	$0.066455
55,000 kWh and above	$0.076455	$0.071455

Generation Capacity, all kWh $0.000171 per kWh

Fuel and Purchased Power:

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.024326	$0.019326
Next 54,500 kWh	$0.034326	$0.029326
55,000 kWh and above	$0.039326	$0.034326

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$2.12 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.23 per month
Customer Delivery	$2.85 per month

Note: Additional meter service charge of $7.00 per month for Three Phase Service.

Energy Charges:

Delivery:

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.048364	$0.043364
Next 54,500 kWh	$0.058364	$0.053364
55,000 kWh and above	$0.063364	$0.058364

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003293 per kWh
System Benefits	$0.000443 per kWh
Transmission	$0.007298 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000171 per kWh

Fuel and Purchased Power:

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.024326	$0.019326
Next 54,500 kWh	$0.034326	$0.029326
55,000 kWh and above	$0.039326	$0.034326

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan GS-11 - FROZEN
Mobile Home Park Electric Service

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

To mobile home parks for service through a master meter to two or more mobile homes, provided each mobile home served through such master meter will be individually metered and billed by the park operator in accordance with applicable Orders of the Arizona Corporation Commission. Electric service to the park's facilities used by its residents may be supplied under this schedule only if such facilities are served through a master meter which serves two or more mobile homes.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service	$ 9.00 per month
Customer Charge, Three Phase service	$16.00 per month
Energy Charges:	
Summer (May – October, all kWh	$0.057820
Winter (November – April), all kWh	$0.051278
Generation Capacity, all kWh	$0.000171
Fuel and Purchased Power, all kWh	$0.034570

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$2.12 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.23 per month
Customer Delivery	$2.85 per month

Note: Additional meter service charge of $7.00 per month for Three Phase Service.

Energy Charges:

Delivery:

Summer (May – October), all kWh	$0.049995 per kWh
Winter (November – April), all kWh	$0.039995 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003293 per kWh
System Benefits	$0.000443 per kWh
Transmission	$0.007298 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity	$0.000171 per kWh
Fuel and Purchased Power	$0.034570 per kWh

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan GS-13 - ELIMINATED
Large General Service

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service. Customer shall contract for a demand of not less than 200 kW.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this rate schedule:

	BILLING MONTHS	
	Summer	Winter
Demand Charge	May-Oct.	Nov.-Apr.
First 200 kW or less per month	$1,675.88	$1,675.88
All additional kW per month @	$6.52	$6.52
Energy Charge		
All kWh @	$0.063744	$0.060556

Minimum Bill

The Demand Charge, but not less than $1,675.88 per month.

BILLING DEMAND

The maximum 15 minute measured demand in the month, but not less than 50% of the maximum demand used for billing purposes in the preceding 11 months, nor less than the contract demand, nor less than 200 kW.

ADJUSTMENT FOR TRANSFORMER OWNERSHIP AND METERING

(a) When Company owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above schedule subject to a discount of 10.3¢ per kW per month of the billing demand each month.

(b) When Customer owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above schedule subject to a discount of 20.6¢ per kW per month of the billing demand each month.

(c) When Customer owns transformers and, at Company's option, energy is metered on secondary side of transformers, the demand shall be metered and the above schedule subject to a discount of 10.3¢ per kW per month of the billing demand each month.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

Service Connection Charges

1. There shall be a $13.50 charge for the initial establishment of each new service for each Customer.

2. There shall be a $13.50 charge for the re-establishment of each service for each Customer.

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this rate schedule.

The Company may require a written contract and a minimum term of contract.

Optional rates are or may become available for certain classes of Customers. Upon application for service or upon request the Company will assist the Customer in selecting the rate schedule best suited to the Customer's requirements, but Company does not guarantee that Customers will be served under the most favorable rate schedule. Upon written notification of any material changes in Customer's installation, load conditions, or use of service, Company will assist in determining if a change in rates is desirable, but not more than one such change in rates will be made within any twelve month period.

Pricing Plan GS-31
Interruptible Agricultural Pumping

AVAILABILITY

Available for interruptible service to agricultural pumping customers throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

Applicable to separately metered interruptible agricultural water pumping service for irrigation purposes of the Customer only.

Not applicable to resale, breakdown, standby, auxiliary, or any other service except agricultural pumping in accordance with the provisions of this rate schedule.

CHARACTER OF SERVICE

Three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges:

Summer (May – October)	$0.027500 per kWh
Winter (November – April)	$0.022500 per kWh
Generation Capacity	$0.000171 per kWh
Fuel and Purchased Power	$0.032811 per kWh

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

DETERMINATION OF HORSEPOWER FOR BILLING

Horsepower connected shall be the manufacturer's nameplate rating of all equipment of Customer connected for service under this schedule, but not less than 60 hp.

MINIMUM BILL

The Customer guarantees that its load shall be sufficient such that a summation of all the above payments shall be not less than $30.00 per hp connected per contract year (which shall be from April 1 to March 31 of the following year) and in no event less than $1,800.00 per contract year. Minimum payments at the rate of $2.50 per hp of motors connected, but not less than $150.00 shall be made monthly.

If during the contract year the total payments exceed the annual guarantee of $30.00 per hp connected but not less than $1,800.00, then the Customer shall be credited the difference between the amount actually paid during the contract year and the amount which would have been paid had the monthly minimum charge not been applied.

TERMS AND CONDITIONS OF SERVICE

1. Customer must furnish, install, own, and maintain at each point of delivery all necessary Company approved equipment which will enable the Company to interrupt service with its master control station.

2. Service may be interrupted by Company during certain periods of the day not exceeding six hours in any 24-hour period.

3. Company will endeavor to give customer one hour notice of impending interruption; however, service may be interrupted without notice should Company deem such action necessary.

4. Where service other than agricultural pumping to which this rate is applicable has been taken hereunder, the general service rate shall be applied on a monthly basis to all usage billed hereunder during the previous twelve months less the aggregate of payments made hereunder for the same period of time. The general service rate shall continue to apply until the unauthorized service is permanently separated from the agricultural pumping service.

5. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy Charges:

Delivery:	
Summer (May – October)	$0.014409 per kWh
Winter (November – April)	$0.009409 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003293 per kWh
System Benefits	$0.000443 per kWh
Transmission	$0.007298 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity	$0.000171 per kWh
Fuel and Purchased Power	$0.032811 per kWh

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4

Transmission Credit – Rider No. 5.

Pricing Plan GS-76 - ELIMINATED
General Service Time-of-Use

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises. Direct access to the meter during normal working hours is also a prerequisite for this Schedule. Service hereunder shall be limited to either an aggregate customer total of 30 MW or an aggregate customer total of 130,000,000 kWh annually, whichever total is reached first.

APPLICABILITY

To any Customer entitled to service under Price Schedule No. 10. Service under this Schedule will commence when the appropriate meter has been installed.*

Customers must stay on this Schedule for a minimum period of one (1) year. A Customer, at his/her discretion and after being served for a twelve (12) month period under Price Schedule No. 76, may opt to switch service to the Company's non-time-of-use General Service Price Schedule No. 10. The Company shall refund to the Customer any excess moneys paid in total over the entire twelve months under Price Schedule No. 76 that would not have been paid under Price Schedule No. 10. A Customer shall be eligible to receive such a refund of excess moneys on a single occasion only.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

PRICE SCHEDULE

A monthly net bill at the following unit prices plus any adjustments incorporated in this Schedule:

	BILLING MONTHS	
	Summer	Winter
Single Phase Service	May-Oct.	Nov.-Apr.
Customer Charge per month	$6.78	$6.78
On-Peak kWh @	$0.222943	$0.150244
Shoulder kWh @	$0.140551	N/A
Off-Peak kWh @	$0.067853	$0.053312

Three Phase Service

Same as Single Phase Service, except a three phase additional charge of $7.36 per month shall apply to Customers receiving three phase service.

Minimum Bill

$6.78 for Single Phase Service
$14.14 for Three Phase Service

The Company has the option to price service in the billing months of May and October at lower levels, which levels shall not be less than marginal cost. Any shoulder consumption remaining from October usage will be billed at the summer shoulder price in following billing months.

The summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day). All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

ADJUSTMENT FOR TRANSFORMER OWNERSHIP AND METERING

(a) When Company owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above schedule subject to a discount of 10.3¢ per kW per month of the billing demand each month.

(b) When Customer owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above schedule subject to a discount of 20.6¢ per kW per month of the billing demand each month.

(c) When Customer owns transformers and, at Company's option, energy is metered on secondary side of transformers, the demand shall be metered and the above schedule subject to a discount of 10.3¢ per kW per month of the billing demand each month.

TAX CLAUSE

To the charges computed under the above prices, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

Service Connection Charges

1. There shall be a $13.50 charge for the initial establishment of each new service for each Customer.

2. There shall be a $13.50 charge for the re-establishment of each service for each Customer.

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this Schedule.

The Company may require a written contract and a minimum term of contract.

Optional price schedules are or may become available for certain classes of Customers. Upon application for service or upon request the Company will assist the Customer in selecting the price schedule best suited to the Customer's requirements, but the Company does not guarantee that Customers will be served under the most favorable price schedule. Upon written notification of any material changes in Customer's installation, load conditions, or use of service, Company will assist in determining if a change in price schedule is desirable, but not more than one such change in price schedule will be made within any twelve month period.

*This Schedule requires a type of meter not normally used; therefore, the Company makes no guarantee that the meters will be installed within any specific time. However, the Company will make its best effort to install the special meter within a reasonable time.

Pricing Plan GS-76N
General Service Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service	$ 9.00 per month
Customer Charge, Three Phase service	$16.00 per month

Energy Charges:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.098319	$0.062509	$0.048819
Next 54,500 kWh	$0.108319	$0.072509	$0.058819
55,000 kWh and above	$0.113319	$0.077509	$0.063819

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.087290	$0.037790
Next 54,500 kWh	$0.097290	$0.047790
55,000 kWh and above	$0.102290	$0.052790

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak: there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

Generation Capacity, all kWhs $0.000171 per kWh

Fuel and Purchased Power:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.061190	$0.025380	$0.011690
Next 54,500 kWh	$0.071190	$0.035380	$0.021690
55,000 kWh and above	$0.076190	$0.040380	$0.026690

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.050161	$0.000661
Next 54,500 kWh	$0.060161	$0.010661
55,000 kWh and above	$0.065161	$0.015661

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$2.12 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.23 per month
Customer Delivery	$2.85 per month

Note: Additional meter service charge of $7.00 per month for Three Phase Service.

Energy Charges:

Delivery:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.085228	$0.049418	$0.035728
Next 54,500 kWh	$0.095228	$0.059418	$0.045728
55,000 kWh and above	$0.100228	$0.064418	$0.050728

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.074199	$0.024699
Next 54,500 kWh	$0.084199	$0.034699
55,000 kWh and above	$0.089199	$0.039699

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003293 per kWh
System Benefits	$0.000443 per kWh
Transmission	$0.007298 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity	$0.000171 per kWh

Fuel and Purchased Power:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.061190	$0.025380	$0.011690
Next 54,500 kWh	$0.071190	$0.035380	$0.021690
55,000 kWh and above	$0.076190	$0.040380	$0.026690

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.050161	$0.000661
Next 54,500 kWh	$0.060161	$0.010661
55,000 kWh and above	$0.065161	$0.015661

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;
Transmission and Ancillary Services – Rider No. 3;
Termination Costs Regulatory Asset – Rider No. 4;
Transmission Credit – Rider No. 5.

Pricing Plan GS-85N
General Service Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge $371.88 per month

Demand Charges:

On-peak $3.00 per kW
Off-peak $1.00 per kW

Energy Charges:

	SUMMER (May – October)	WINTER (November – April)
On-peak	$0.056992	$0.052310
Shoulder-peak	$0.041076	N/A
Off-peak	$0.035742	$0.031060

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak: there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

Generation Capacity, all kWhs $0.000171 per kWh

Fuel and Purchased Power:

	SUMMER (May – October)	WINTER (November – April)
On-peak	$0.072176	$0.060679
Shoulder-peak	$0.036366	N/A
Off-peak	$0.022676	$0.011179

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and jthe above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$223.13 per month
Meter Reading	$ 18.59 per month
Billing & Collection	$111.56 per month
Customer Delivery	$ 18.59 per month

Energy Charges:

Delivery:

On-peak	$3.00 per kW
Off-peak	$1.00 per kW

	SUMMER (May – October)	WINTER (November – April)
On-peak	$0.043901	$0.039219
Shoulder-peak	$0.027985	N/A
Off-peak	$0.022651	$0.017969

Fixed Must-Run (See Must-Run Generation – Rider No. 2) $0.003293 per kWh

System Benefits $0.000443 per kWh

Transmission $0.007298 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000171 per kWh

Fuel and Purchased Power:

	SUMMER (May – October)	WINTER (November – April)
On-peak	$0.072176	$0.060679
Shoulder-peak	$0.036366	N/A
Off-peak	$0.022676	$0.011179

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;
Transmission and Ancillary Services – Rider No. 3;
Termination Costs Regulatory Asset – Rider No. 4;
Transmission Credit – Rider No. 5.

Pricing Plan LLP-90A - ELIMINATED
Large Light and Power Time-of-Use

AVAILABILITY

Price Schedule No. 90 shall be available for any Customer within the service territory of the Company if the Company has facilities of adequate capacity and a written contract, covering such matters as the Company and Customer shall deem appropriate. Service under this Schedule shall commence when the appropriate meter has been installed.*

CHARACTER OF SERVICE

Service shall be three phase, 60 Hertz, and shall be supplied directly from any 46,000 volt, or higher voltage, system through distribution facilities used exclusively to serve Price Schedule No. 90 customers at a delivery voltage of not less than 2400/4160 volts and delivered at a single point of delivery unless otherwise specified in the contract.

PRICE

Monthly net bills shall reflect the following prices plus any adjustments incorporated in this Schedule:

	BILLING MONTHS	
	Summer	Winter
Demand Charge per Month	May-Oct.	Nov.-Apr.
On-peak demand All kW - per kW	$10.95	$8.99
Shoulder demand in excess of 150% of the On-peak demand - per kW	$7.23	N/A
Off-peak demand in excess of 150% of the On-peak demand - per kW	$5.40	$4.42
Energy Charge		
On-Peak kWh	$0.058806	$0.058806
Shoulder kWh	$0.049005	N/A
Off-peak kWh	$0.041654	$0.041654

Excess shoulder demand is defined as that positive amount (if any) by which shoulder demand exceeds 150% of on-peak period demand.

Excess off-peak demand is defined as:

I. that positive amount by which off-peak period demand exceeds shoulder period demand (when and if shoulder period demand is greater than 150% of the on-peak period demand and off-peak period demand exceeds shoulder period demand), or;
II. that positive amount by which off-peak period demand exceeds 150% of the on-peak period demand (when and if shoulder period demand is less than 150% of the on-peak period demand and off-peak period demand exceeds 150% of the on-peak period demand), or;
III. zero when the above conditions in I are not met and the above conditions in II are not met.

In the event that excess shoulder and/or excess off-peak demand occur, excess shoulder demand shall be billed at the shoulder price and excess off-peak demand shall be billed at the off-peak price.

Any shoulder consumption remaining from October usage shall be billed at the summer shoulder price in following billing months.

The summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day). All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

BILLING DEMAND

The billing demand shall be specified in the contract, but shall not be less than 3,000 kW. Additionally, the On-Peak billing demand shall not be less than 66.67% of the maximum On-Peak billing demand in the preceding eleven (11) months, unless otherwise specified in the contract.

POWER FACTOR ADJUSTMENT

Prices are subject to a discount or a charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is above or below 90% lagging to a maximum discount of 13.0¢ per kW of billing demand per month.

TAX CLAUSE

To the charges computed under the above prices, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this Schedule.

The Company shall require a written contract and a minimum term of contract.

Optional price schedules are or may become available for certain classes of Customers. Upon application for service or upon request the Company will assist the Customer in selecting the price schedule best suited to the Customer's requirements, but Company does not guarantee that Customers will be served under the most favorable schedule. Upon written notification of any material changes in Customer's installation, load conditions, or use of service, the Company shall assist in determining if a change in schedule is desirable, but not more than one such change shall be made within any twelve month period.

*This Schedule requires a type of meter that is not normally used; therefore, the Company makes no guarantee that meters shall be installed within any specific time. However, the Company shall make its best effort to install the special meter within a reasonable time.

Pricing Plan LLP-90F (Frozen Rate) - ELIMINATED
Large Light and Power Time-of-Use

AVAILABILITY

Price Schedule No. 90 shall be available for any Customer within the service territory of the Company if the Company has facilities of adequate capacity and a written contract, covering such matters as the Company and Customer shall deem appropriate. Service under this Schedule shall commence when the appropriate meter has been installed.* Service under this Schedule is available upon Customer's request through November 23, 1998. Customers not choosing this Schedule on or before November 23, 1998, shall be ineligible to choose this service after this date. Customers choosing this Schedule on or before November 23, 1998, shall be eligible for service hereunder, until this Schedule is terminated by Commission approval.

CHARACTER OF SERVICE

Service shall be three phase, 60 Hertz, and shall be supplied directly from any 46,000 volt, or higher voltage, system through distribution facilities used exclusively to serve Price Schedule No. 90 customers at a delivery voltage of not less than 2400/4160 volts and delivered at a single point of delivery unless otherwise specified in the contract.

PRICE

Monthly net bills shall reflect the following prices plus any adjustments incorporated in this Schedule:

	BILLING MONTHS	
	Summer	Winter
Demand Charge per Month	May-Oct.	Nov.-Apr.
On-peak demand All kW - per kW	$20.34	$10.73
Shoulder demand in excess of 150% of the On-peak demand - per kW	$13.43	N/A
Off-peak demand in excess of 150% of the On-peak demand -per kW	$10.18	$5.38
Energy Charge		
On-Peak kWh	$0.083541	$0.042003
Shoulder kWh	$0.042003	N/A
Off-peak kWh	$0.028002	$0.028002

Excess shoulder demand is defined as that positive amount (if any) by which shoulder demand exceeds 150% of on-peak period demand.

Excess off-peak demand is defined as:

I. that positive amount by which off-peak period demand exceeds shoulder period demand (when and if shoulder period demand is greater than 150% of the on-peak period demand and off-peak period demand exceeds shoulder period demand), or;

II. that positive amount by which off-peak period demand exceeds 150% of the on-peak period demand (when and if shoulder period demand is less than 150% of the on-peak period demand and off-peak period demand exceeds 150% of the on-peak period demand), or;

III. zero when the above conditions in I are not met and the above conditions in II are not met.

In the event that excess shoulder and/or excess off-peak demand occur, excess shoulder demand shall be billed at the shoulder price and excess off-peak demand shall be billed at the off-peak price.

Any shoulder consumption remaining from October usage shall be billed at the summer shoulder price in following billing months.

The summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day). All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

BILLING DEMAND

The billing demand shall be specified in the contract, but shall not be less than 3,000 kW. Additionally, the On-Peak billing demand shall not be less than 66.67% of the maximum On-Peak billing demand in the preceding eleven (11) months, unless otherwise specified in the contract.

POWER FACTOR ADJUSTMENT

Prices are subject to a discount or a charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is above or below 90% lagging to a maximum discount of 13.0¢ per kW of billing demand per month.

TAX CLAUSE

To the charges computed under the above prices, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this Schedule.

The Company shall require a written contract and a minimum term of contract.

Optional price schedules are or may become available for certain classes of Customers. Upon application for service or upon request the Company will assist the Customer in selecting the price schedule best suited to the Customer's requirements, but Company does not guarantee that Customers will be served under the most favorable schedule. Upon written notification of any material changes in Customer's installation, load conditions, or use of service, the Company shall assist in determining if a change in schedule is desirable, but not more than one such change shall be made within any twelve month period.

*This Schedule requires a type of meter that is not normally used; therefore, the Company makes no guarantee that meters shall be installed within any specific time. However, the Company shall make its best effort to install the special meter within a reasonable time.

Pricing Plan GS-85F (Frozen Rate) - ELIMINATED
Large General Service Time-of-Use

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises. Service under this Schedule shall be limited to a total of 30 MW. Service under this Schedule is available upon Customer's request through November 23, 1998. Customers not choosing this Schedule on or before November 23, 1998, shall be ineligible to choose this service after this date. Customers choosing this Schedule on or before November 23, 1998, shall be eligible for service hereunder, until this Schedule is terminated by Commission approval.

APPLICABILITY

To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service. Customer shall contract for a demand of not less than 200 kW. Service under this Schedule shall commence when the appropriate meter has been installed.*

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

PRICE

Monthly net bills shall reflect the following prices plus any adjustments incorporated in this Schedule:

	BILLING MONTHS	
	Summer May-Oct.	Winter Nov.-Apr.
Customer Charge per Month	$94.60	$94.60
Demand Charge per Month		
On-peak demand All kW - per kW	$16.34	$9.10
Shoulder demand in excess of 150% of the On-peak demand – per kW	$10.80	N/A
Off-peak demand in excess of 150% of the On-peak demand - per kW	$8.19	$4.54

Pricing Plan GS-85F (Frozen Rate) - ELIMINATED
Large General Service Time-of-Use

	BILLING MONTHS	
	Summer May-Oct.	Winter Nov.-Apr.
Energy Charge		
On-Peak kWh	$0.104973	$0.076808
Shoulder kWh	$0.076808	N/A
Off-peak kWh	$0.031320	$0.031320

Excess shoulder demand is defined as that positive amount (if any) by which shoulder demand exceeds 150% of on-peak period demand.

Excess off-peak demand is defined as:

I. that positive amount by which off-peak period demand exceeds shoulder period demand (when and if shoulder period demand is greater than 150% of the on-peak period demand and off-peak period demand exceeds shoulder period demand), or;

II. that positive amount by which off-peak period demand exceeds 150% of the on-peak period demand (when and if shoulder period demand is less than 150% of the on-peak period demand and off-peak period demand exceeds 150% of the on-peak period demand), or;

III. zero when the above conditions in I are not met and the above conditions in II are not met.

In the event that excess shoulder and/or excess off-peak demand occur, excess shoulder demand shall be billed at the shoulder price and excess off-peak demand shall be billed at the off-peak price.

Any shoulder consumption remaining from October usage shall be billed at the summer shoulder price in following billing months.

The summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day). All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

BILLING DEMAND

The maximum 60-minute measured demand in the month, but not less than 50% of the maximum on-peak demand used for billing purposes in the preceding 11 months, nor less than 50% of the contract demand, nor less than 200 kW.

ADJUSTMENT FOR TRANSFORMER OWNERSHIP AND METERING

(a) When Company owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above Schedule subject to a discount of 10.3¢ per kW per month of the billing demand each month.

(b) When Customer owns transformers and, at Company's option, energy is metered on secondary side of transformers, the demand shall be metered and the above Schedule subject to a discount of 10.3¢ per kW per month of the billing demand each month.

TAX CLAUSE

To the charges computed under the above prices, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this Schedule.

The Company shall require a written contract and a minimum term of contract.

Optional price schedules are or may become available for certain classes of Customers. Upon application for service or upon request the Company will assist the Customer in selecting the price schedule best suited to the Customer's requirements, but Company does not guarantee that Customers will be served under the most favorable schedule. Upon written notification of any material changes in Customer's installation, load conditions, or use of service, the Company shall assist in determining if a change in schedule is desirable, but not more than one such change shall be made within any twelve month period.

*This Schedule requires a type of meter that is not normally used; therefore, the Company makes no guarantee that meters shall be installed within any specific time. However, the Company shall make its best effort to install the special meter within a reasonable time.

Pricing Plan GS-85A - ELIMINATED
Large General Service Time-of-Use

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises. Service under this Schedule shall be limited to a total of 30 MW.

APPLICABILITY

To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service. Customer shall contract for a demand of not less than 200 kW. Service under this Schedule shall commence when the appropriate meter has been installed.*

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

PRICE

Monthly net bills shall reflect the following prices plus any adjustments incorporated in this Schedule:

	BILLING MONTHS	
	Summer May-Oct.	Winter Nov.-Apr.
Customer Charge per Month	$98.01	$98.01
Demand Charge per Month		
On-peak demand All kW - per kW	$7.50	$4.96
Shoulder demand in excess of 150% of the On-peak demand - per kW	$4.96	N/A
Off-peak demand in excess of 150% of the On-peak demand - per kW	$3.75	$2.48

Pricing Plan GS-85A - ELIMINATED
Large General Service Time-of-Use

	BILLING MONTHS	
	Summer May-Oct.	Winter Nov.-Apr.
Energy Charge		
On-Peak kWh	$0.069587	$0.065667
Shoulder kWh	$0.065667	N/A
Off-peak kWh	$0.061746	$0.057826

Excess shoulder demand is defined as that positive amount (if any) by which shoulder demand exceeds 150% of on-peak period demand.

Excess off-peak demand is defined as:

I. that positive amount by which off-peak period demand exceeds shoulder period demand (when and if shoulder period demand is greater than 150% of the on-peak period demand and off-peak period demand exceeds shoulder period demand), or;

II. that positive amount by which off-peak period demand exceeds 150% of the on-peak period demand (when and if shoulder period demand is less than 150% of the on-peak period demand and off-peak period demand exceeds 150% of the on-peak period demand), or;

III. zero when the above conditions in I are not met and the above conditions in II are not met.

In the event that excess shoulder and/or excess off-peak demand occur, excess shoulder demand shall be billed at the shoulder price and excess off-peak demand shall be billed at the off-peak price.

Any shoulder consumption remaining from October usage shall be billed at the summer shoulder price in following billing months.

The summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day). All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

BILLING DEMAND

The maximum 60-minute measured demand in the month, but not less than 50% of the maximum on-peak demand used for billing purposes in the preceding 11 months, nor less than 50% of the contract demand, nor less than 200 kW.

ADJUSTMENT FOR TRANSFORMER OWNERSHIP AND METERING

(a) When Company owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above Schedule subject to a discount of 10.3¢ per kW per month of the billing demand each month.

(b) When Customer owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above Schedule subject to a discount of 20.6¢ per kW per month of the billing demand each month.

(c) When Customer owns transformers and, at Company's option, energy is metered on secondary side of transformers, the demand shall be metered and the above Schedule subject to a discount of 10.3¢ per kW per month of the billing demand each month.

TAX CLAUSE

To the charges computed under the above prices, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this Schedule.

The Company shall require a written contract and a minimum term of contract.

Optional price schedules are or may become available for certain classes of Customers. Upon application for service or upon request the Company will assist the Customer in selecting the price schedule best suited to the Customer's requirements, but Company does not guarantee that Customers will be served under the most favorable schedule. Upon written notification of any material changes in Customer's installation, load conditions, or use of service, the Company shall assist in determining if a change in schedule is desirable, but not more than one such change shall be made within any twelve month period.

*This Schedule requires a type of meter that is not normally used; therefore, the Company makes no guarantee that meters shall be installed within any specific time. However, the Company shall make its best effort to install the special meter within a reasonable time.

Pricing Plan LLP-90N
Large Light and Power Service Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

CHARACTER OF SERVICE
Service shall be three phase, 60 Hertz, Primary Service, and shall be supplied directly from any 46,000 volt, or higher voltage, system at a delivery voltage of not less than 13,800 volts and delivered at a single point of delivery unless otherwise specified in the contract.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge $500.00 per month

Demand Charges:
On-peak $8.00 per kW
Off-peak $2.66 per kW

Energy Charges:

	Summer (May – October)	Winter (November - April)
On-Peak	$0.032692	$0.028722
Shoulder-Peak	$0.023012	N/A
Off-Peak	$0.020192	$0.016222

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak: there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

Generation Capacity, all kWhs $0.000343 per kWh

Fuel and Purchased Power:

	Summer (May – October)	Winter (November - April)
On-Peak	$0.039680	$0.028840
Shoulder-Peak	$0.030000	N/A
Off-Peak	$0.027180	$0.035710

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

PRIMARY SERVICE

The above rate is subject to Primary Service and Metering. The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers

POWER FACTOR ADJUSTMENT

The above rate is subject to a discount or a charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is above or below 90% lagging to a maximum discount of 13.0¢ per kW of billing demand per month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$300.00 per month
Meter Reading	$025.00 per month
Billing & Collection	$150.00 per month
Customer Delivery	$025.00 per month

Energy Charges:

Delivery:

On-peak	$8.00 per kW
Off-peak	$2.66 per kW

	Summer (May – October)	Winter (November - April)
On-Peak	$0.020925	$0.016955
Shoulder-Peak	$0.011245	N/A
Off-Peak	$0.008425	$0.004455

Fixed Must-Run (See Must-Run Generation – Rider No. 2) $0.003408 per kWh

System Benefits $0.000433 per kWh

Transmission $0.006184 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000084 per kWh
Reactive Supply and Voltage Control	$0.000330 per kWh
Regulation and Frequency Response	$0.000320 per kWh
Spinning Reserve Service	$0.000867 per kWh
Supplemental Reserve Service	$0.000141 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000343 per kWh

Fuel and Purchased Power:

	Summer (May – October)	Winter (November - April)
On-Peak	$0.039680	$0.028840
Shoulder-Peak	$0.027180	N/A
Off-Peak	$0.030000	$0.035710

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;
Transmission and Ancillary Services – Rider No. 3;
Termination Costs Regulatory Asset – Rider No. 4;
Transmission Credit – Rider No. 5.

Pricing Plan LLP-14 - ELIMINATED
Large Light and Power Service

AVAILABILITY

Rate No. 14 shall be available for any Customer within the service territory of the Company if the Company has facilities of adequate capacity and a written contract, covering such matters as the Company and Customer shall deem appropriate.

CHARACTER OF SERVICE

Service shall be three phase, 60 Hertz, and shall be supplied directly from any 46,000 volt, or higher voltage, system through distribution facilities used exclusively to serve Rate 14 customers at a delivery voltage of not less than 2400/4160 volts and delivered at a single point of delivery unless otherwise specified in the contract.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this rate schedule:

	BILLING MONTHS	
	Summer	Winter
Demand Charge	May-Oct.	Nov.-Apr.
Per kW of Billing Demand per month	$9.97	$9.97
Energy Charge		
All kWh @	$0.046001	$0.043701

BILLING DEMAND

The billing demand shall be specified in the contract, but shall not be less than 3,000 kW. Additionally, the billing demand shall not be less than 66.67% of the maximum billing demand in the preceding eleven (11) months, unless otherwise specified in the contract.

POWER FACTOR ADJUSTMENT

The above rate is subject to a discount or a charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is above or below 90% lagging to a maximum discount of 13.0¢ per kW of billing demand per month.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

Pricing Plan PS-40
Municipal Service

AVAILABILITY

Available for Municipal Service where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

Applicable for service to the City of Tucson and City of South Tucson for Municipal buildings and grounds.

Not applicable to resale, breakdown, standby, or auxiliary service or to buildings used for residential purposes.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, at secondary voltage and subject to availability at point of delivery approved by the Company.

RATE

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges:	
Summer (May – October, all kWh	$0.061737
Winter (November – April), all kWh	$0.051737
Generation Capacity, all kWhs	$0.000312
Fuel and Purchased Power:	
Summer (May – October, all kWh	$0.035837
Winter (November – April), all kWh	$0.025837

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy Charges:	
Delivery:	
Summer (May – October, all kWh	$0.050158
Winter (November – April), all kWh	$0.040158
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003289 per kWh

System Benefits	$0.000434 per kWh
Transmission	$0.006129 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000083 per kWh
Reactive Supply and Voltage Control	$0.000327 per kWh
Regulation and Frequency Response	$0.000317 per kWh
Spinning Reserve Service	$0.000860 per kWh
Supplemental Reserve Service	$0.000140 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Generation Capacity	$0.000312 per kWh

Fuel and Purchased Power:

Summer (May – October, all kWh	$0.035837
Winter (November – April), all kWh	$0.025837

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan PS-41
Traffic Signal and Street Lighting Service

AVAILABILITY
Available for service to the State, a county, city, town, political subdivision, improvement district, or a responsible person or persons for unincorporated communities for Traffic Signal and Street Lighting purposes where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Applicable to Customer owned and maintained traffic signals and public street and highway lighting.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery approved by the Company.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

All kWh @ $0.050196 per kWh

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

Generation Capacity, all kWh	$0.0003163 per kWh
Fuel and Purchased Power, per kWh	$0.029484 per kWh

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Delivery	$0.013207 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.002305 per kWh
System Benefits	$0.000413 per kWh
Transmission	$0.026736 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000363 per kWh
Reactive Supply and Voltage Control	$0.001427 per kWh
Regulation and Frequency Response	$0.001383 per kWh
Spinning Reserve Service	$0.003750 per kWh
Supplemental Reserve Service	$0.000612 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity	$0.000163 per kWh
Fuel and Purchased Power:	$0.029484

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan PS-43
Municipal Water Pumping Service

AVAILABILITY
Available for service to the City of Tucson Water Utility and private water Companies where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Applicable for service to booster stations and wells used for domestic water supply.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as elected by Customer and subject to availability at point of delivery approved by the Company. Primary metering may be used by mutual agreement.

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges:

Summer (May – October, all kWh		$0.061737
Winter (November – April), all kWh		$0.051737
Generation Capacity, all kWh		$0.000312
Fuel and Purchased Power:		
Summer (May – October, all kWs	$0.049500	
Winter (November – April), all kWh	$0.039500	

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy Charges:

Delivery:

Summer (May – October, all kWh	$0.050158
Winter (November – April), all kWh	$0.040158
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003289 per kWh
System Benefits	$0.000434 per kWh

Transmission	$0.006129 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000083 per kWh
Reactive Supply and Voltage Control	$0.000327 per kWh
Regulation and Frequency Response	$0.000317 per kWh
Spinning Reserve Service	$0.000860 per kWh
Supplemental Reserve Service	$0.000140 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Generation Capacity	$0.000312 per kWh
Fuel and Purchased Power:	
Summer (May – October, all kWh	$0.049500
Winter (November – April), all kWh	$0.039500

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TERMS AND CONDITIONS OF INTERRUPTIBLE SERVICE

1. Customer must furnish, install, own, and maintain at each point of delivery all necessary Company approved equipment which will enable the Company to interrupt service with its master control station.

2. Service may be interrupted by Company during certain periods of the day not exceeding six hours in any 24-hour period.

3. Company will endeavor to give Customer one hour notice of impending interruption; however, service may be interrupted without notice should Company deem such action necessary.

4. The interruptible load shall be separately served and metered and shall at no time be connected to facilities serving Customer's firm load. Conversely, the firm load shall be separately served and metered and shall at no time be connected to facilities serving Customer's interruptible load.

5. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan GS-51
Private Street and Area Lighting Service

AVAILABILITY
At any point where the Company in its judgment has facilities of adequate capacity and suitable voltage available.

APPLICABILITY
To any Customer for private street or outdoor area lighting where this service can be supplied from existing facilities of the Company.

Service is from dusk to dawn and the Company will install, own, operate, and maintain the complete lighting installation including lamp replacements.

Not applicable to resale service.

CHARACTER OF SERVICE
Multiple or series street lighting system at option of Company and at one standard nominal voltage.

BUNDLED STANDARD OFFER SERVICE

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
per unit per month	$9.56	$9.56	$9.56	$14.34	$22.13	$18.10	$3.34

Note:

The watt high pressure sodium lamps are charged per unit per month.

Per one pole addition and an extension of up to 100 feet of overhead service are charged per pole.

Underground Service is per 100 watt or less high pressure sodium lamp unit per month mounted on standard pole.

Generation Capacity:	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
Fuel and Purchased Power	$0.0027	$9.56	$9.56	$14.34	$22.13	$18.10	$3.34

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

STANDARD LAMP UNITS, OVERHEAD SERVICE

(1) The standard 100 watt lamp unit for overhead service is a 9,500 lumen high pressure sodium unit, mounted on a four foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 25 feet above ground level.

(2) The standard 250 watt lamp unit for overhead service is a 27,500 lumen high pressure sodium unit, mounted on an eight foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 27 feet above ground level.

(3) The standard 400 watt lamp unit for overhead service is a 50,000 lumen high pressure sodium unit, mounted on an eighteen foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 35 feet above ground level.

(4) The standard 100 watt lamp unit for underground service is a 9,500 lumen high pressure sodium post top unit mounted on a pole approximately 15 feet above ground level.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Delivery	$8.95	$8.78	$8.45	$0.12	$17.68
Fixed Must-Run	$0.04	$0.05	$0..07	$0.17	$0.28
System Benefits	$0.01	$0.01	$0.01	$0.03	$0.05
Transmission	$0.44	$0.56	$0.80	$2.01	$3.21
Transmission Ancillary					
System Control & Load Dispatch	$0.01	$0.01	$0.01	$0.03	$0.04
Reactive Supply and Voltage Control	$0.02	$0.03	$0.04	$0.12	$0.17
Regulation and Frequency Response	$0.02	$0.03	$0.04	$0.10	$0.17
Spinning Reserve Service	$0.06	$0.08	$0.11	$0.28	$0.45
Supplemental Reserve Service	$0.01	$0.01	$0.02	$0.05	$0.07
Energy Imbalance Service: currently charged pursuant to the Company's OATT.					
Generation Capacity:	$0.01	$.01	$0.01	$0.01	$0.02
Fuel and Purchased Power	$0.49	$0.62	$0.89	$2.22	$3.54

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

SPECIAL PROVISIONS

(1) Installation of a light on an existing pole is subject to prior approval of Company.

(2) For underground service, where customer provides trenching up to 10 feet in accordance with Company's electric service requirements, customer shall be billed at the rates for overhead service.

(3) Extensions beyond 100 feet and all installations other than those addressed in this pricing plan will require specific agreements providing adequate revenue or arrangements for construction financing.

(4) The Customer is not authorized to make connections to this lighting circuit or to make attachments or alterations to the Company owned pole.

(5) If a Customer requests a relocation of a lighting installation, the costs of such relocation must be borne by the Customer.

(6) The Customer is expected to notify the Company when lamp outages occur.

(7) The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

(8) After the minimum contract period, if any, has expired, this agreement shall be extended from year to year unless written notice of desire to terminate is given by either party at least thirty (30) days prior to the end of any such annual extension date.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan PS-50
Public Street Lighting Service

AVAILABILITY
Available for service for lighting public streets, alleys, thoroughfares, public parks, and playgrounds by use of Company's standard facilities where such service is contracted under this pricing plan by the state, a county, city, town, political subdivision, improvement district, or a responsible person or persons for unincorporated communities.

APPLICABILITY
Applicable to street lighting service from dusk to dawn and Company will own, operate, and maintain the street light system including lamps and globe replacements.

CHARACTER OF SERVICE
Multiple or series street lighting system at option of Company and at one standard nominal voltage.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
per unit per month	$9.56	$9.56	$9.56	$14.34	$22.13	$18.10	$3.34

Note:

The watt high pressure sodium lamps are charged per unit per month.

Per one pole addition and an extension of up to 100 feet of overhead service are charged per pole.

Underground Service is per 100 watt or less high pressure sodium lamp unit per month mounted on standard pole.

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Generation Capacity	$0.0027	$0.0034	$0.0049	$0.0122	$0.0196
Fuel & Purchased Power	$0.4874	$0.6203	$0.8862	$2.2154	$3.5447

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

STANDARD LAMP UNITS, OVERHEAD SERVICE

(1) The standard 100 watt lamp unit for overhead service is a 9,500 lumen high pressure sodium unit, mounted on a four foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 25 feet above ground level.

(2) The standard 250 watt lamp unit for overhead service is a 27,500 lumen high pressure sodium unit, mounted on an eight foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 27 feet above ground level.

(3) The standard 400 watt lamp unit for overhead service is a 50,000 lumen high pressure sodium unit, mounted on an eighteen foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 35 feet above ground level.

(4) The standard 100 watt lamp unit for underground service is a 9,500 lumen high pressure sodium post top unit mounted on a pole approximately 15 feet above ground level.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Delivery	$8.95	$8.78	$8.45	$0.12	$17.68
Fixed Must-Run	$0.04	$0.05	$0.07	$0.17	$0.28
System Benefits	$0.01	$0.01	$0.01	$0.03	$0.05
Transmission	$0.44	$0.56	$0.80	$2.01	$3.21
Transmission Ancillary					
System Control & Load Dispatch	$0.01	$0.01	$0.01	$0.03	$0.04
Reactive Supply and Voltage Control	$0.02	$0.03	$0.04	$0.12	$0.17
Regulation and Frequency Response	$0.02	$0.03	$0.04	$0.10	$0.17
Spinning Reserve Service	$0.06	$0.08	$0.11	$0.28	$0.45
Supplemental Reserve Service	$0.01	$0.01	$0.02	$0.05	$0.07
Energy Imbalance Service: currently charged pursuant to the Company's OATT.					
Generation Capacity:	$0.01	$.01	$0.01	$0.01	$0.02
Fuel and Purchased Power	$0.49	$0.62	$0.89	$2.22	$3.54

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

SPECIAL PROVISIONS

(1) Installation of a light on an existing pole is subject to prior approval of Company.

(2) For underground service, where customer provides trenching up to 10 feet in accordance with Company's electric service requirements, customer shall be billed at the rates for overhead service.

(3) Extensions beyond 100 feet and all installations other than those addressed in this pricing plan will require specific agreements providing adequate revenue or arrangements for construction financing.

(4) The Customer is not authorized to make connections to this lighting circuit or to make attachments or alterations to the Company owned pole.

(5) If a Customer requests a relocation of a lighting installation, the costs of such relocation must be borne by the Customer.

(6) The Customer is expected to notify the Company when lamp outages occur.

(7) The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

(8) After the minimum contract period, if any, has expired, this agreement shall be extended from year to year unless written notice of desire to terminate is given by either party at least thirty (30) days prior to the end of any such annual extension date.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Rider 2
Must-Run Generation

Variable Component	$	0.015000 per kWh
Fixed Component		
Residential Service	$	0.005017 per kWh
General Service - Rates No. 10 and 76		0.005493 per kWh
Mobile Home Parks - Rate No. 11		0.006549 per kWh
Interruptible Agricultural Pumping - Rate No. 31		0.003752 per kWh
Large General Service - Rates No. 13, 85 and 85A		0.003787 per kWh
Large Light & Power - Rates No. 14, 90, and 90A		0.002900 per kWh
Lighting - Rates No. 41, 50 and 51		0.004522 per kWh
Public Authority - Rates No. 40 and 43		0.004876 per kWh
(Weighted Average Fixed Component)	$	0.004320 per kWh

Variable component is billed to scheduling coordinator based on actual must-run energy delivered.
Fixed component is billed directly to end-use customer.

During a month in which must-run generation is provided to meet retail load, the Market Price component used in calculating the on-peak MGC shall be a weighted average of the Palo Verde NYMEX futures price and the must-run variable cost charges that are levied on scheduling coordinators serving retail customers in the TEP load zone during that month, consistent with AISA protocols.

Rider 3
Transmission & Ancillary Services

Transmission

Group "A" : For customers under 20 kW and not demand metered.

Applicability: Required for Direct Access Service pursuant to the Company's OATT. The rates in Transmission Credit -- Rider No. 5 will be used for the Transmission Credit in the calculation of the floating CTC. These rates are based on the Company's OATT, but are converted to a kWh-basis for specific load-profiled customer groups. For illustrative purposes, estimated rates are shown in selected Direct Access tariffs.

Note: A loss factor adjustment shall be made for transmission and ancillary services.

Group "B" : For customers not in Group A.

Applicability: Required for Direct Access Service pursuant to the Company's OATT. The following OATT rate is shown below for information and for calculation of the floating CTC (See Transmission Rider No. 3).

As of June 7, 1999, the transmission charges are as follows:

EHV	Non-EHV	
2.259	$0.757000	per kW / Month

Note: A loss factor adjustment shall be made for transmission and ancillary services.

Ancillary Services

Group "A" : For customers under 20 kW and not demand metered.

Applicability: Required for Direct Access Service, but not purchased directly by the customer. Sold to scheduling coordinator pursuant to the OATT. The rates in Transmission Credit -- Rider No. 5 will be used for the Transmission Credit in the calculation of the floating CTC. These rates are based on the Company's OATT, but are converted to a kWh-basis for specific load-profiled customer groups. For illustrative purposes, estimated rates are shown in selected Direct Access tariffs.

Services covered:

1. System Control & Dispatch
2. Reactive Supply and Voltage Control
3. Regulation and Frequency Response
4. Energy Imbalance Service
5. Spinning Reserve Service
6. Supplemental Reserve Service

Notes:
- A loss factor adjustment shall be made for transmission and ancillary services.
- Energy Imbalance Service currently charged pursuant to the Company's OATT, which is subject to change pursuant to AISA protocols.

Group "B" : For customers not in Group A.

Applicability: Required for Direct Access Service pursuant to the Company's OATT. The following OATT rates are shown below for information and for calculation of the floating CTC (See Transmission Rider No. 3).

As of June 7, 1999, the charges are as follows:

Service		
System Control & Dispatch	$0.041000	per kW / Month
Reactive Supply and Voltage Control	$0.161000	per kW / Month
Regulation and Frequency Response	$0.156000	per kW / Month
Energy Imbalance Service	(see note)	
Spinning Reserve Service	$0.423000	per kW / Month
Supplemental Reserve Service	$0.069000	per kW / Month

Notes:
- A loss factor adjustment shall be made for transmission and ancillary services.
- Energy Imbalance Service currently charged pursuant to the Company's OATT, which is subject to change pursuant to AISA protocols.

Rider 4
Termination Costs Regulatory Asset Charge ("TCRAC")

The TCRAC for the period January 1, 2009 through December 31, 2009 shall be $0.012622 per kWh, applicable to all retail Customers.

Notes

1. The planned amortization schedule for the Termination Costs Regulatory Asset is contained in the Calculation of Termination Cost Regulatory Asset Charge, filed with the Commission July 2, 2007, as Exhibit KCG-2 to the direct testimony of Mr. Kentton Grant ("Termination Costs Regulatory Asset Amortization Schedule"). The actual amortization of the Termination Costs Regulatory Asset will depend on actual retail kWh sales.

2. To the extent that actual retail kWh sales in a given year are higher than the projected retail kWh sales for that year, the amortization attributed to that year will be increased, decreasing the unamortized balance of cost that remains to be collected.

3. To the extent that actual retail kWh sales in a given year are lower than the projected retail kWh sales for that year, the amortization attributed to that year will be less than the amount shown in the Calculation of Termination Cost Regulatory Asset Charge, resulting in a higher unamortized balance than would have occurred if sales were as projected.

4. Large Light and Power Service customers with contracts at negotiated rates will be assessed the TCRAC and recorded by the Company. Payment of such TCRAC assessments shall be arranged between the Company and Customer upon expiration of the current contract.

Rider 5
Transmission Cost Adjustment Charge ("TCAC")

The Transmission Cost Adjustment Charge ("TCAC") shall apply to all of the Company's retail pricing plans. All provisions of the applicable pricing plan will apply in addition to the TCAC authorized by this Rider.

Pricing plans to which the TCAC applies include transmission and ancillary service components listed in the table below. The listed transmission and ancillary service components are based on the Company's Federal Energy Regulatory Commission ("FERC") - approved Open Access Transmission Tariff ("OATT"). The listed transmission and ancillary service components are calculated on a volumetric basis by class of service.

Pursuant to this Rider, the TCAC, which is an annual adjustment to the transmission and ancillary service components, will be submitted to the Commission for review. In the event that the Company's FERC-approved OATT changes, TEP will file an additional recalculated TCAC, unless the regular annual adjustment addresses the OATT change. The TCAC is based upon the prior year's annual Transmission and Ancillary Service costs and retail energy sales. Transmission and Ancillary Service costs are calculated by applying the Company's approved OATT rates to TEP's retail jurisdictional sales. This TCAC will be applied volumetrically to kilowatt-hour sales under applicable electric pricing plans. The TCAC applies to all system sales and will not vary by class of service.

The initial transmission and ancillary service components of retail rates and are as follows:

	Residential	General Service	Lg Light & Power	Lighting	Public Authority
Transmission	$0.006950	$0.006740	$0.005711	$0.024692	$0.005660
Ancillary Services					
System Control - Load Dispatch	$0.000094	$0.000092	$0.000078	$0.000336	$0.000077
Reactive Supply and Voltage Control	$0.000371	$0.000360	$0.000305	$0.001318	$0.000302
Regulation and Frequency Response	$0.000359	$0.000349	$0.000295	$0.001277	$0.000293
Spinning Reserve Service	$0.000975	$0.000945	$0.000801	$0.003463	$0.000794
Supplemental Reserve Service	$0.000159	$0.000154	$0.000131	$0.000565	$0.000130

Note: All values presented as $/kWh

Rider 6 - ELIMINATED
Environmental Portfolio Surcharge

APPLICABILITY

The Environmental Portfolio Surcharge (EPS) applies to all customers in all territory served by Tucson Electric Power Company as mandated by the Arizona Corporation Commission.

SURCHARGE

The Environmental Portfolio Surcharge shall be applied to all monthly net bills at the following rates:

All kWh	$0.000875	*per kWh*

SURCHARGE LIMITS

The monthly total Environmental Portfolio Surcharge shall not exceed the following limits:

Residential Customers	$0.35	*per service per month*
Non-Residential Customers	$13.00	*per service per month**
Non-Residential Customers with demand of 3,000 kW or higher per month for three consecutive months	$39.00	*per service per month**

* The EPS will not be assessed to reactive meters or accumulators.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this rate schedule.

Customer bills shall reflect a line item entitled "Environmental Portfolio Surcharge, mandated by the Corporation Commission."

RIDER 17
GreenWatts PRICING PLAN

AVAILABILITY/APPLICABILITY

GreenWatts is a Pricing Plan available to all Customers in all territory served by Tucson Electric Power Company at all points where facilities of the Company are of adequate capacity and are adjacent to the premises.

PRICING PLAN

A participating Customer under the *GreenWatts* Pricing Plan will be charged a monthly before-tax premium to the Customer's existing TEP Pricing Plan according to the following schedule:

First twenty-kWh block of energy @	$2.00
Each additional twenty-kWh block of energy @	$1.50

The number of twenty-kWh blocks purchased is at the discretion of the *GreenWatts* Customer and is subject to the conditions of service described below.

CONDITIONS OF SERVICE

- Revenues from *GreenWatts* will be devoted to the cost of building, operating, and maintaining new solar power sources in the State of Arizona.
- The total kWh under subscription cannot exceed the Customer's minimum monthly consumption during the prior twelve months. For a Customer with an insufficient billing history, subscription is limited to a total of four twenty-kWh blocks per month.
- The *GreenWatts* Customer is responsible for the premium payment for the subscribed number of blocks, regardless of the level of consumption in any given billing period.
- Customer must contact TEP to cancel or change subscriptions to *GreenWatts*. Any change or cancellation of subscription shall take effect in the succeeding billing period.
- All provisions of the Customer's current applicable rate schedule will apply during service under *GreenWatts*.
- Energy provided under *GreenWatts* will be generated by landfill gas from Tucson area landfills, displacing the burning of coal in a Tucson area power plant, and will be blended with solar power sources as solar power sources are constructed. The total amount of energy sold under *GreenWatts* shall not exceed the combined capacity of TEP's landfill gas facilities and solar power sources.
- Energy generated for *GreenWatts* will be delivered to TEP's distribution grid for general distribution.
- The premium charged for *GreenWatts* does not represent the sale or lease of generation assets.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

Rider 79
Pricing Flexibility Rider

AVAILABILITY

Available to commercial and industrial customers qualifying for electric service under any commercial or industrial pricing plan. For purposes of determining a negotiated pricing structure ("negotiated price") for a customer pursuant to this rider, the Company and the customer shall specify a pricing plan under which the customer would be entitled to receive service ("Comparative Pricing Plan"). Availability shall be subject to the Terms and Conditions specified herein.

TERMS AND CONDITIONS OF SERVICE

1. The negotiated price must cover the Company's marginal cost, considering the expected term or duration of service and the type of service offered.

2. The negotiated price cannot exceed the Comparative Pricing Plan price.

3. A customer must document a viable alternative to receiving service under the Comparative Pricing Plan.

4. The negotiated price must be commensurate with the cost to the customer of that customer's alternative(s).

5. The customer must agree to an energy audit unless the customer has recently completed a significant DSM program or energy audit and provides the Company with adequate documentation concerning the DSM activities or audit.

6. Each service under this rider shall be evidenced by a contract. The contract may be for varying lengths of time as determined by individual customer or Company requirements. Each executed contract shall be filed with the Commissioners, Staff and RUCO, on a confidential basis, at least 30 days prior to the effective date of the proposed contract and Staff shall determine whether the contract complies with the pricing plan prior to the effective date. Staff shall be provided with adequate documentation and support of each term listed in this rider (e.g., the customer's alternatives) before the 30-day review period commences. If the negotiated contract complies with the tariff, the contract would not be submitted to the Commission for approval, unless a Commissioner requests a formal vote. The Company and Staff may agree on standardized contracts for qualifying customers under 200 kW. To the extent that negotiated contract elements adhere to such a standardized contract, the Company may implement the negotiated elements without Commission approval, unless a Commissioner requests a formal vote. The Company shall notify Staff and RUCO of such contracts by providing a term sheet acceptable to TEP, Staff and RUCO.

7. The Company's shareholders shall be responsible for any foregone revenue resulting from the rider.

8. The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate schedule.

Rider 84
Interruptible Service Rider

AVAILABILITY
Available to customers receiving and qualifying for electric service under pricing plans applicable to service over 200 kW. .

CHARACTER OF SERVICE
Must meet all service requirements for the applicable pricing plan.

DISCOUNT
Customers that elect service under this rider will receive a credit (discount) on their bills.

TERMS AND CONDITIONS OF SERVICE

1. A customer qualifying for service as a Large Light & Power customer (greater than or equal to ,3000 kW) service shall contract for a demand of not less than 1,000 kW; a customer qualifying as a Large General Service (greater than or equal to 200 kW but less than 3,000 kW) shall contract for a demand of not less than 200 kW.

2. The customer must give the Company three years' notice to convert interruptible load to firm load.

3. Customers that elect service under this rider will receive a credit (discount) on their bills. The discount, the maximum number of interruptions per year, the time interval in which customer must comply with Company's request for load reduction, the penalty for customer's failure to comply, and the term of contract will be negotiated on a customer by customer basis.

4. The interruptible load shall be served and metered as provided for in the contract.

5. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

6. The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate schedule.

REDLINED VERSION

Tucson Electric Power
The Energy People

Pricing Plan R-01 FROZEN
Residential Electric Service

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single phase or three phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter; however, electric water heating may be metered separately.

Not applicable to resale, breakdown, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, nominal 120/240 volts.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service $ 9.00 per month

Customer Charge, Three Phase service $15.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.048208	$0.043208
Next 3,000 kWh	$0.058208	$0.053208
3,501 kWh and above	$0.063208	$0.058208

_____Generation Capacity, all kWh $0.000322 per kWh

_____Fuel and Purchased Power:

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.027684	$0.022684
Next 3,000 kWh	$0.037684	$0.032684
3,501 kWh and above	$0.042684	$0.037684

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.51 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.29 per month
Customer Delivery	$3.40 per month

Note: Additional meter service charge of $6.00 per month for Three Phase Service.

Energy (kWh) and Demand Charges (kW):

Delivery

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.034246	$0.029246
Next 3,000 kWh	$0.044246	$0.039246
3,501 kWh and above	$0.049246	$0.044246

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000322 per kWh

Fuel and Purchased Power

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.027684	$0.022684
Next 3,000 kWh	$0.037684	$0.032684
3,501 kWh and above	$0.042684	$0.037684

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan R-02 FROZEN
Residential Electric Water Heating Service

AVAILABILITY
This rate is limited to installations and customers served under Pricing Plan No. 2 on the effective date of this tariff sheet.

APPLICABILITY
To separately metered single phase residential off-peak water heating service where general residential service is also provided under Pricing Plan No. 1. When service under Pricing Plan No. 2 is discontinued, the Company will either combine usage and bill under Pricing Plan No. 1 or modify the service entrance equipment so all service is supplied through the Pricing Plan No. 1 meter.

Not applicable to three phase service, resale, breakdown, standby, auxiliary, or any other service except off-peak water heating in accordance with the provisions of this pricing plan.

Where service other than water heating to which this rate is applicable has been taken hereunder, the regular rate for such service shall be applied on a monthly basis to all consumption billed hereunder during the previous twelve months, less the aggregate of payments made hereunder for the same period of time. The regular rate shall continue to apply until the unauthorized service is permanently separated from the off-peak water heating service.

CHARACTER OF SERVICE
Single phase, 60 Hertz, nominal 120/240 volts.

Service may be controlled by the Company by disconnecting electricity during certain periods of the day not exceeding 8 hours in any 24-hour period, as determined by the Company from time to time.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges:

Delivery, all kWh	$0.050000 per kWh
Generation Capacity, all kWh	$0.000322 per kWh
Fuel and Purchased Power, all kWh	$0.034570 per kWh

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

Tucson Electric Power
The Energy People

Pricing Plan R-02 FROZEN
Residential Electric Water Heating Service

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Deleted: (kWh)

Energy:

Delivery	$0.036038 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Generation Capacity	$0.000322 per kWh
Fuel and Purchased Power	$0.034570 per kWh

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

The electric water heating equipment and installation shall conform to the Company's requirements and be for normal domestic use. The heater shall be of the storage type and not less than 30-gallon capacity. For a water heater equipped with one heating element, the rating of the heating element shall not exceed 6,000 watts. For a water heater equipped with more than one heating element, the rating of any such heating element shall not exceed 6,000 watts, and, if the total of the ratings of the elements exceeds 6,000 watts, they shall be thermostatically interlocked so that they cannot operate simultaneously and thereby exceed 6,000 watts. The Customer shall provide the necessary wiring to permit the installation of the Company's metering and control equipment.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Deleted: The Company's following Riders may apply to this tariff: ¶ Must-Run Generation – Rider No. 2; ¶ Transmission and Ancillary Services – Rider No. 3; ¶ Termination Costs Regulatory Asset – Rider No. 4¶ Transmission Credit -- Rider No. 5.

Inserted: The Company's following Riders may apply to this tariff: ¶ Must-Run Generation -- Rider No. 2; ¶ Transmission and Ancillary Services – Rider No. 3;

Inserted: Transmission Credit -- Rider No. 5.

Tucson Electric Power
The Energy People

Pricing Plan R-21 - ELIMINATED
Residential Time-of-Use

Deleted: (Frozen Rate)

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises. Direct access to the meter during normal working hours is also a prerequisite for this rate schedule.

APPLICABILITY

To any Customer entitled to single phase service under Rate 01. Preference may be given to those Customers whose historic or expected annual usage exceeds 16,000 kWh. Service must be single phase residential electric service in individual private dwellings and individually metered multi-family units when all service is supplied at one point of delivery and energy is metered through one meter; however, controlled off-peak electric water heating may be metered separately.

Not applicable to three phase service, resale, breakdown, temporary, standby, or auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

The total number of Customers served under this Time-of-Use Rate Schedule is limited to 5,000. Service under this schedule will commence when the appropriate meter has been installed.* Customers must stay on this Rate Schedule for a minimum period of one (1) year.

The waiting list for service under this Time-of-Use Rate Schedule was frozen as of March 31, 1996.

As meters become available from the original group of 5,000, customers on the frozen waiting list will be offered service under this Rate Schedule in the order that they were placed on the waiting list.

Customers currently served under this Rate Schedule that change residences will *not* be allowed to receive service under this Rate Schedule at their new residence.

CHARACTER OF SERVICE

Single phase, 60 Hertz, nominal 120/240 volts.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this rate schedule:

	BILLING MONTHS	
	Summer May-Oct.	Winter Nov.-Apr.
Customer Charge per month	$6.86	$6.86
On-Peak kWh per month	$0.125413	$0.099018
Off-Peak kWh per month	$0.050165	$0.050165
Minimum Bill per month	$6.86	$6.86

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Deleted: Steven J. Glaser
Inserted: Heyman
Deleted: Vice President, Rates and Regulatory Support
Deleted: July 1, 2000
Deleted: Entire Electric Service Area
Deleted: 2

Deleted: (Frozen Rate)

During the summer season, the On-Peak period is 10:00 a.m. to 10:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). During the winter season, the On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day). All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

Service Connection Charges

1. There shall be a $13.50 charge for the initial establishment of each new service for each Customer.

2. There shall be a $13.50 charge for the re-establishment of each service for each Customer.

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this rate schedule.

Optional rates are or may become available for certain classes of Customers. Upon application for service or upon request the Company will assist the Customer in selecting the rate schedule best suited to the Customer's requirements, but Company does not guarantee that Customers will be served under the most favorable rate schedule. Upon written notification of any material changes in Customer's installation, load conditions, or use of service, Company will assist in determining if a change in rates is desirable, but not more than one such change in rates will be made within any twelve month period.

Electric space heating and water heating equipment and installation shall conform to the Company's requirements.

*This Rate Schedule requires a type of meter that is not normally used; therefore, the Company makes no guarantee that meters will be installed within any specific time. However, the Company will make its best effort to install the special meter within a reasonable time.

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Deleted: Steven J. Glaser

Inserted: Heyman

Deleted: Vice President, Rates and Regulatory Support

Deleted: July 1, 2000

Deleted: Entire Electric Service Area

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Pricing Plan R-70 - ELIMINATED
Residential Time-of-Use

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises. Direct access to the meter during normal working hours is also a prerequisite for this rate schedule.

APPLICABILITY

To any Customer entitled to single phase service under Rate No. 01. Service is available to individual private dwellings and individually metered multi-family units when all service is supplied at one point of delivery and energy is metered through one meter; however, controlled off-peak electric water heating may be metered separately.

Not applicable to three phase service, resale, breakdown, temporary, standby, or auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

Service under this schedule will commence when the appropriate meter has been installed.* Customers must stay on this Rate Schedule for a minimum period of one (1) year. A Customer, at his/her discretion and after being served for a twelve (12) month period under Rate No. 70, may opt to switch service to the Company's non-time-of-use Residential Rate No. 1. The Company shall refund to the Customer any excess moneys paid in total over the entire twelve months under Rate No. 70 that would not have been paid under Rate No. 1. A Customer shall be eligible to receive such a refund of excess moneys on a single occasion only.

CHARACTER OF SERVICE

Single phase, 60 Hertz, nominal 120/240 volts.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this rate schedule:

	Billing Months	
	Summer May-Oct.	Winter Nov.-Apr.
Customer Charge	$6.78	$6.78
On-Peak kWh @	$0.184171	$0.126011
Shoulder kWh @	$0.116318	N/A
Off-Peak kWh @	$0.058160	$0.043619
Minimum Bill per month	$6.78	$6.78

The Company has the option to price service in the billing months of May and October at lower levels, which levels shall not be less than marginal cost. Any shoulder consumption remaining from October usage will be billed at the summer shoulder rate in following billing months.

Deleted: July 1, 2000

The summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day). All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

Service Connection Charges

1. There shall be a $13.50 charge for the initial establishment of each new service for each Customer.
2. There shall be a $13.50 charge for the re-establishment of each service for each Customer.

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this rate schedule.

Optional rates are or may become available for certain classes of Customers. Upon application for service or upon request the Company will assist the Customer in selecting the rate schedule best suited to the Customer's requirements, but Company does not guarantee that Customers will be served under the most favorable rate schedule. Upon written notification of any material changes in Customer's installation, load conditions, or use of service, Company will assist in determining if a change in rates is desirable, but not more than one such change in rates will be made within any twelve month period.

Electric space heating and water heating equipment and installation shall conform to the Company's requirements.

*This Rate Schedule requires a type of meter that is not normally used; therefore, the Company makes no guarantee that meters will be installed within any specific time. However, the Company will make its best effort to install the special meter within a reasonable time.

Deleted: July 1, 2000

Tucson Electric Power
The Energy People

Pricing Plan R-70N
Residential Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Service is available to individual private dwellings and individually metered multi-family units when all service is supplied at one point of delivery and energy is metered through one meter; however, controlled off-peak electric water heating may be metered separately.

Not applicable to three phase service, resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

Service under this pricing plan will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
Single phase, 60 Hertz, nominal 120/240 volts.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge: $9.00 per month

Energy Charges:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.083474	$0.049169	$0.033974
Next 3,000 kWh	$0.093474	$0.059169	$0.043974
3,501 kWh and above	$0.098474	$0.064169	$0.048974

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.071135	$0.021635
Next 3,000 kWh	$0.081135	$0.031635
3,501 kWh and above	$0.086135	$0.036635

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak: there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

If a Summer or Winter holiday falls on Saturday, the preceding Friday is designated off-peak; if a holiday falls on Sunday, the following Monday is designated off-peak.

Energy Charges continued:

Generation Capacity $0.000322 per kWh

Fuel and Purchased Power:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.062950	$0.028645	$0.013450
Next 3,000 kWh	$0.072950	$0.038645	$0.023450
3,501 kWh and above	$0.077950	$0.043645	$0.028450

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.050611	$0.001111
Next 3,000 kWh	$0.060611	$0.011111
3,501 kWh and above	$0.065611	$0.016111

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTSOF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.51 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.29 per month
Customer Delivery	$3.40 per month

Deleted: Note: Additional meter service charge of $6.00 per month for Three Phase Service.

Tucson Electric Power
The Energy People

Pricing Plan R-70N
Residential Time-of-Use

Energy (kWh):

Delivery

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.069512	$0.035207	$0.020012
Next 3,000 kWh	$0.079512	$0.045207	$0.030012
3,501 kWh and above	$0.084512	$0.050207	$0.035012

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.057173	$0.007673
Next 3,000 kWh	$0.067173	$0.017673
3,501 kWhs and above	$0.072173	$0.022673

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Generation Capacity	$0.000322 per kWh

Fuel and Purchased Power:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.062950	$0.028645	$0.013450
Next 3,000 kWh	$0.072950	$0.038645	$0.023450
3,501 kWh and above	$0.077950	$0.043645	$0.028450

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.050611	$0.001111
Next 3,000 kWh	$0.060611	$0.011111
3,501 kWh and above	$0.065611	$0.016111

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

Deleted:

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan R-201 - ELIMINATED
Special Residential Electric Service

AVAILABILITY

In all territory served by Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served. Access to the meter during normal working hours is also a prerequisite for Options B & C of this Schedule.

APPLICABILITY

To single phase or three phase (Option A only) (subject to availability at point of delivery) electric service in individual residences as described in current program details when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this Schedule requires that the customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below and that the customer's home conform to the standards of the Heating, Cooling and Comfort Guarantee program as in effect at the time of subscription to this Schedule. Notwithstanding the above, the customer's use of solar energy for any purpose shall not preclude subscription to this Schedule. Three different Options are available under this Schedule: A, B, & C. Subscription eligibility requirements are as follows:

- Option A: Customer must meet conditions outlined above;
- Option B: Customer must meet conditions required for option A and must purchase under the time-of-use structure applicable to Option B. Applicable only to single phase service.
- Option C: Customer must meet above conditions required for option A, must use either (i.) solar equipment for water heating requirements during the year or (ii.) an electric heat pump water heater, or both (i.) and (ii.), and must purchase under the time-of-use structure applicable to Option C. Applicable only to single phase service.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

Service under Option B or Option C of this Schedule will commence when the appropriate meter has been installed.* Customers must stay on Option B or Option C of this Schedule for a minimum period of one (1) year. A Customer, at his/her discretion and after being served for a twelve (12) month period under Option B or Option C of this Schedule, may opt to switch service to the non-time-of-use Option A of this Schedule. The Company shall refund to the Customer any excess moneys paid in total over the entire twelve months under Rate No. 201, Option B or Option C that would not have been paid under Rate No. 201A. A Customer shall be eligible to receive such a refund of excess moneys on a single occasion only.

CHARACTER OF SERVICE

Single or three phase (Option A only), 60 Hertz, nominal 120/240 volts.

PRICE UNDER OPTION A

Monthly net bills shall reflect the following prices plus any adjustments incorporated in this Schedule:

Single Phase Service	
Customer Charge per month	$4.90
All kWh consumed in mid-summer season of June 1 - August 31 @	$0.090920
All kWh consumed in remaining summer season of May 1 - May 31 & September 1 - October 31 @	$0.074191
All kWh consumed in winter season of November 1 - April 30 @	$0.064440

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Three Phase Service
Same as Single Phase Service, except a three phase additional charge of $7.36 per month shall apply to Customers receiving three phase service.

Minimum Bill
$4.90 for Single Phase Service
$12.26 for Three Phase Service

PRICE UNDER OPTION B
Monthly net bills shall reflect the following prices plus any adjustments incorporated in this Schedule:

	CONSUMPTION MONTHS		
	Mid-Summer Jun.-Aug.	Remaining Summer May & Sept.-Oct.	Winter Nov.-Apr.
Customer Charge	$6.78	$6.78	$6.78
On-Peak kWh @	$0.184171	$0.146415	$0.100179
Shoulder kWh @	$0.116318	$0.092473	N/A
Off-Peak kWh @	$0.058160	$0.046236	$0.034673
Minimum Bill per month	$6.78	$6.78	$6.78

The Company has the option to price service in the billing months of May and October at lower levels, which levels shall not be less than marginal cost. Any shoulder consumption remaining from October usage will be billed at the shoulder summer shoulder price in following billing months.

The summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day). All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

PRICE UNDER OPTION C
Monthly net bills shall reflect the following prices plus any adjustments incorporated in this Schedule:

	CONSUMPTION MONTHS		
	Mid-Summer Jun.-Aug.	Remaining Summer May & Sept.-Oct.	Winter Nov.-Apr.
Customer Charge	$6.78	$6.78	$6.78
On-Peak kWh @	$0.184171	$0.137207	$0.093879
Shoulder kWh @	$0.116318	$0.086658	N/A
Off-Peak kWh @	$0.058160	$0.043328	$0.032491
Minimum Bill per month	$6.78	$6.78	$6.78

The Company has the option to price service in the billing months of May and October at lower levels, which levels shall not be less than marginal cost. Any shoulder consumption remaining from October usage will be billed at the shoulder summer shoulder price in following billing months.

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The summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day). All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

TAX CLAUSE

To the charges computed under the above prices, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

Service Connection Charges

1. There shall be a $13.50 charge for the initial establishment of each new service for each Customer.

2. There shall be a $13.50 charge for the re-establishment of each service for each Customer.

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this Schedule.

Optional price schedules are or may become available for certain classes of Customers. Upon application for service or upon request the Company will assist the Customer in selecting the price schedule best suited to the Customer's requirements, but Company does not guarantee that Customers will be served under the most favorable schedule. Upon written notification of any material changes in Customer's installation, load conditions, or use of service, the Company shall assist in determining if a change in schedule is desirable, but not more than one such change shall be made within any twelve month period.

Electric space heating and water heating equipment and installation shall conform to the Company's requirements.

*This Schedule requires a type of meter not normally used; therefore, the Company makes no guarantee that the meters will be installed within any specific time. However, the Company will make its best effort to install the special meter within a reasonable time.

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Pricing Plans:
R-201A FROZEN,
R-201BN AND R-201CN
Special Residential Electric Service

AVAILABILITY
Throughout the entire area where facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To single phase electric service in individual residences as described in current program details when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this Schedule requires that the customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below and that the customer's home conform to the standards of the Heating, Cooling and Comfort Guarantee program as in effect at the time of subscription to this Schedule. Notwithstanding the above, the customer's use of solar energy for any purpose shall not preclude subscription to this Schedule. Two different Options are available under this Schedule: BN, & CN. Subscription eligibility requirements are as follows:

Option A: This option is FROZEN to new customers.
Option BN: Customer must meet above conditions and must purchase under the time-of-use structure.
Option CN: Customer must meet above conditions and must use either (i.) solar equipment for water heating requirements during the year or (ii.) an electric heat pump water heater, or both (i.) and (ii.), and must purchase under the time-of-use structure applicable to Option CN.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
Single phase, 60 Hertz, nominal 120/240 volts.

PRICE UNDER OPTION A
A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Minimum Customer Charge $ 9.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.049000	$0.044000	$0.041500
Next 3,000 kWh	$0.059000	$0.054000	$0.051500
3,501 kWh and above	$0.064000	$0.059000	$0.056500

Generation Capacity, all kWh $0.000322 per kWh

Fuel and Purchase Power:

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.021076	$0.016076	$0.013576
Next 3,000 kWh	$0.031076	$0.026076	$0.023576
3,501 kWh and above	$0.036076	$0.031076	$0.028576

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

PRICE UNDER OPTION BN

A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Minimum Customer Charge $ 9.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.051000	$0.041000	$0.036000
Next 3,000 kWh	$0.061000	$0.051000	$0.046000
3,501 kWh and above	$0.056000	$0.046000	$0.041000

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.046000	$0.036000	$0.031000
Next 3,000 kWh	$0.056000	$0.046000	$0.041000
3,501 kWh and above	$0.051000	$0.041000	$0.036000

The Mid-Summer and Remaining Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day:

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.
Off-Peak is 8:00 p.m. to 12:00 p.m.
On-Peak is 2:00 p.m. to 6:00 p.m.

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.043500	$0.038500
Next 3,000 kWh	$0.053500	$0.048500
3,501 kWh and above	$0.048500	$0.043500

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day:

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: there are no shoulder peak periods in the winter.
Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

If a Summer or Winter holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

Energy Charges continued:

Generation Capacity $0.000322 per kWh

Fuel and Purchased Power:

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.028076	$0.018076	$0.013076
Next 3,000 kWh	$0.038076	$0.028076	$0.023076
3,501 kWh and above	$0.033076	$0.023076	$0.018076

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.023076	$0.013076	$0.008076
Next 3,000 kWh	$0.033076	$0.023076	$0.018076
3,501 kWh and above	$0.028076	$0.018076	$0.013076

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.020576	$0.015576
Next 3,000 kWh	$0.030576	$0.025576
3,501 kWh and above	$0.025576	$0.020576

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchase Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

PRICE UNDER OPTION CN
A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Minimum Customer Charge $ 9.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.049980	$0.040180	$0.035280
Next 3,000 kWh	$0.059780	$0.049980	$0.045080
3,501 kWh and above	$0.054880	$0.045080	$0.040180

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.045080	$0.035280	$0.030380
Next 3,000 kWh	$0.054880	$0.045080	$0.040180
3,501 kWh and above	$0.049980	$0.040180	$0.035280

The Mid-Summer and Remaining Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day:

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.
Off-Peak is 8:00 p.m. to 12:00 p.m.
On-Peak is 2:00 p.m. to 6:00 p.m.

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.042630	$0.037730
Next 3,000 kWh	$0.052430	$0.047530
3,501 kWh and above	$0.047530	$0.042630

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day:

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: there are no shoulder peak periods in the winter.
Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

If a Summer or Winter holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

Energy Charges continued:

Generation Capacity $0.000322 per kWh

Fuel and Purchase Power:

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.026734	$0.016934	$0.012034
Next 3,000 kWh	$0.036534	$0.026734	$0.021834
3,501 kWh and above	$0.031634	$0.021834	$0.016934

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.021834	$0.012034	$0.007134
Next 3,000 kWh	$0.031634	$0.021834	$0.016934
3,501 kWh and above	$0.026734	$0.016934	$0.012034

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.019384	$0.014484
Next 3,000 kWh	$0.029184	$0.024284
3,501 kWh and above	$0.024284	$0.019384

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchase Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE R-201A FROZEN, R-201BN AND R201CN CONSIST OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.51 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.29 per month
Customer Delivery	$3.40 per month

Note: Additional meter service charge of $6.00 per month for Three Phase Service.

Energy:

Delivery **(FOR OPTION A ONLY):**

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.035038	$0.030038	$0.027538
Next 3,000 kWh	$0.045038	$0.040038	$0.037538
3,501 kWh and above	$0.050038	$0.045038	$0.042538

Delivery **(FOR OPTION BN ONLY):**

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.037038	$0.027038	$0.022038
Next 3,000 kWh	$0.047038	$0.037038	$0.032038
3,501 kWh and above	$0.042038	$0.032038	$0.027038

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.032038	$0.022038	$0.017038
Next 3,000 kWh	$0.042038	$0.032038	$0.027038
3,501 kWh and above	$0.037038	$0.027038	$0.022038

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.029538	$0.024538
Next 3,000 kWh	$0.039538	$0.034538
3,501 kWh and above	$0.034538	$0.029538

Delivery **(FOR OPTION CN ONLY):**

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.036018	$0.026218	$0.021318
Next 3,000 kWh	$0.045818	$0.036018	$0.031118
3,501 kWh and above	$0.040918	$0.031118	$0.026218

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.031118	$0.021318	$0.016418
Next 3,000 kWh	$0.040918	$0.031118	$0.026218
3,501 kWh and above	$0.036018	$0.026218	$0.021318

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.028668	$0.023768
Next 3,000 kWh	$0.038468	$0.033568
3,501 kWh and above	$0.033568	$0.028668

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003849 per kWh
System Benefits	$0.000468 per kWh
Transmission	$0.007525 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity	$0.000322 per kWh

Fuel and Purchased Power:

(FOR OPTION A ONLY):

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.021076	$0.016076	$0.013576
Next 3,000 kWh	$0.031076	$0.026076	$0.023576
3,501 kWh and above	$0.036076	$0.031076	$0.028576

(FOR OPTION BN ONLY):

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.028076	$0.018076	$0.013076
Next 3,000 kWh	$0.038076	$0.028076	$0.023076
3,501 kWh and above	$0.033076	$0.023076	$0.018076

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.023076	$0.013076	$0.008076
Next 3,000 kWh	$0.033076	$0.023076	$0.018076
3,501 kWh and above	$0.028076	$0.018076	$0.013076

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.020576	$0.015576
Next 3,000 kWh	$0.030576	$0.025576
3,501 kWh and above	$0.025576	$0.020576

(FOR OPTION CN ONLY):

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.026734	$0.016934	$0.012034
Next 3,000 kWh	$0.036534	$0.026734	$0.021834
3,501 kWh and above	$0.031634	$0.021834	$0.016934

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.021834	$0.012034	$0.007134
Next 3,000 kWh	$0.031634	$0.021834	$0.016934
3,501 kWh and above	$0.026734	$0.016934	$0.012034

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.019384	$0.014484
Next 3,000 kWh	$0.029184	$0.024284
3,501 kWh and above	$0.024284	$0.019384

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan R-06
Residential Lifeline Discount

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

To electric service qualifying for billing under an approved and available Residential Pricing Plan where the customer also has qualified for Rate No. 5 as specified in the Company's plan for administration. All provisions of the Company's residential pricing plan chosen for service will apply except as modified herein. This discount is also available to tenants of master metered mobile home parks and apartments.

MONTHLY BILL

The monthly bill shall be in accordance with an applicable Residential Pricing Plan except that a discount of $8.00 per month shall be applied. This notwithstanding, the minimum monthly bill shall be zero. That is, the $8.00 monthly discount cannot be used to create a negative monthly bill (i.e., when the monthly bill before the discount is less than $8.00, and an $8.00 discount would otherwise create a bill credit for the month).

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Pricing Plan GS-10 FROZEN
General Service

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service $ 9.00 per month

Customer Charge, Three Phase service $16.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.061455	$0.056455
Next 54,500 kWh	$0.071455	$0.066455
55,000 kWh and above	$0.076455	$0.071455

Generation Capacity, all kWh $0.000171 per kWh

Fuel and Purchased Power:

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.024326	$0.019326
Next 54,500 kWh	$0.034326	$0.029326
55,000 kWh and above	$0.039326	$0.034326

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$2.12 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.23 per month
Customer Delivery	$2.85 per month

Note: Additional meter service charge of $7.00 per month for Three Phase Service.

Energy Charges:

Delivery:

—	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.048364	$0.043364
Next 54,500 kWh	$0.058364	$0.053364
55,000 kWh and above	$0.063364	$0.058364

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003293 per kWh
System Benefits	$0.000443 per kWh
Transmission	$0.007298 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000171 per kWh

Fuel and Purchased Power:

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.024326	$0.019326
Next 54,500 kWh	$0.034326	$0.029326
55,000 kWh and above	$0.039326	$0.034326

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan GS-11 - FROZEN
Mobile Home Park Electric Service

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

To mobile home parks for service through a master meter to two or more mobile homes, provided each mobile home served through such master meter will be individually metered and billed by the park operator in accordance with applicable Orders of the Arizona Corporation Commission. Electric service to the park's facilities used by its residents may be supplied under this schedule only if such facilities are served through a master meter which serves two or more mobile homes.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service	$ 9.00 per month
Customer Charge, Three Phase service	$16.00 per month
Energy Charges:	
Summer (May – October, all kWh	$0.057820
Winter (November – April), all kWh	$0.051278
Generation Capacity, all kWh	$0.000171
Fuel and Purchased Power, all kWh	$0.034570

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$2.12 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.23 per month
Customer Delivery	$2.85 per month

Note: Additional meter service charge of $7.00 per month for Three Phase Service.

Energy Charges:

Delivery:	
Summer (May – October), all kWh	$0.049995 per kWh
Winter (November – April), all kWh	$0.039995 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003293 per kWh
System Benefits	$0.000443 per kWh
Transmission	$0.007298 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity	$0.000171 per kWh
Fuel and Purchased Power	$0.034570 per kWh

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan GS-13 - ELIMINATED
Large General Service

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service. Customer shall contract for a demand of not less than 200 kW.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this rate schedule:

	BILLING MONTHS	
	Summer	Winter
Demand Charge	May-Oct.	Nov.-Apr.
First 200 kW or less per month	$1,675.88	$1,675.88
All additional kW per month @	$6.52	$6.52
Energy Charge		
All kWh @	$0.063744	$0.060556

Minimum Bill

The Demand Charge, but not less than $1,675.88 per month.

BILLING DEMAND

The maximum 15 minute measured demand in the month, but not less than 50% of the maximum demand used for billing purposes in the preceding 11 months, nor less than the contract demand, nor less than 200 kW.

ADJUSTMENT FOR TRANSFORMER OWNERSHIP AND METERING

(a) When Company owns transformers and energy is metered on primary side of transformers, the demand ~~shall be metered and the above~~ schedule subject to a discount of 10.3¢ per kW per month of the billing demand each month.

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(b) When Customer owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above schedule subject to a discount of 20.6¢ per kW per month of the billing demand each month.

(c) When Customer owns transformers and, at Company's option, energy is metered on secondary side of transformers, the demand shall be metered and the above schedule subject to a discount of 10.3¢ per kW per month of the billing demand each month.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

Service Connection Charges

1. There shall be a $13.50 charge for the initial establishment of each new service for each Customer.

2. There shall be a $13.50 charge for the re-establishment of each service for each Customer.

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this rate schedule.

The Company may require a written contract and a minimum term of contract.

Optional rates are or may become available for certain classes of Customers. Upon application for service or upon request the Company will assist the Customer in selecting the rate schedule best suited to the Customer's requirements, but Company does not guarantee that Customers will be served under the most favorable rate schedule. Upon written notification of any material changes in Customer's installation, load conditions, or use of service, Company will assist in determining if a change in rates is desirable, but not more than one such change in rates will be made within any twelve month period.

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Pricing Plan GS-31
Interruptible Agricultural Pumping

AVAILABILITY

Available for interruptible service to agricultural pumping customers throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

Applicable to separately metered interruptible agricultural water pumping service for irrigation purposes of the Customer only.

Not applicable to resale, breakdown, standby, auxiliary, or any other service except agricultural pumping in accordance with the provisions of this rate schedule.

CHARACTER OF SERVICE

Three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges:

Summer (May – October)	$0.027500 per kWh
Winter (November – April)	$0.022500 per kWh
Generation Capacity	$0.000171 per kWh
Fuel and Purchased Power	$0.032811 per kWh

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

DETERMINATION OF HORSEPOWER FOR BILLING

Horsepower connected shall be the manufacturer's nameplate rating of all equipment of Customer connected for service under this schedule, but not less than 60 hp.

MINIMUM BILL

The Customer guarantees that its load shall be sufficient such that a summation of all the above payments shall be not less than $30.00 per hp connected per contract year (which shall be from April 1 to March 31 of the following year) and in no event less than $1,800.00 per contract year. Minimum payments at the rate of $2.50 per hp of motors connected, but not less than $150.00 shall be made monthly.

If during the contract year the total payments exceed the annual guarantee of $30.00 per hp connected but not less than $1,800.00, then the Customer shall be credited the difference between the amount actually paid during the contract year and the amount which would have been paid had the monthly minimum charge not been applied.

TERMS AND CONDITIONS OF SERVICE

1. Customer must furnish, install, own, and maintain at each point of delivery all necessary Company approved equipment which will enable the Company to interrupt service with its master control station.

2. Service may be interrupted by Company during certain periods of the day not exceeding six hours in any 24-hour period.

3. Company will endeavor to give customer one hour notice of impending interruption; however, service may be interrupted without notice should Company deem such action necessary.

4. Where service other than agricultural pumping to which this rate is applicable has been taken hereunder, the general service rate shall be applied on a monthly basis to all usage billed hereunder during the previous twelve months less the aggregate of payments made hereunder for the same period of time. The general service rate shall continue to apply until the unauthorized service is permanently separated from the agricultural pumping service.

5. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy Charges:	
Delivery:	
Summer (May – October)	$0.014409 per kWh
Winter (November – April)	$0.009409 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003293 per kWh
System Benefits	$0.000443 per kWh
Transmission	$0.007298 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Generation Capacity	$0.000171 per kWh
Fuel and Purchased Power	$0.032811 per kWh

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4

Transmission Credit – Rider No. 5.

Pricing Plan GS-76 - ELIMINATED
General Service Time-of-Use

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises. Direct access to the meter during normal working hours is also a prerequisite for this Schedule. Service hereunder shall be limited to either an aggregate customer total of 30 MW or an aggregate customer total of 130,000,000 kWh annually, whichever total is reached first.

APPLICABILITY

To any Customer entitled to service under Price Schedule No. 10. Service under this Schedule will commence when the appropriate meter has been installed.*

Customers must stay on this Schedule for a minimum period of one (1) year. A Customer, at his/her discretion and after being served for a twelve (12) month period under Price Schedule No. 76, may opt to switch service to the Company's non-time-of-use General Service Price Schedule No. 10. The Company shall refund to the Customer any excess moneys paid in total over the entire twelve months under Price Schedule No. 76 that would not have been paid under Price Schedule No. 10. A Customer shall be eligible to receive such a refund of excess moneys on a single occasion only.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

PRICE SCHEDULE

A monthly net bill at the following unit prices plus any adjustments incorporated in this Schedule:

	BILLING MONTHS	
	Summer	Winter
Single Phase Service	May-Oct.	Nov.-Apr.
Customer Charge per month	$6.78	$6.78
On-Peak kWh @	$0.222943	$0.150244
Shoulder kWh @	$0.140551	N/A
Off-Peak kWh @	$0.067853	$0.053312

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Three Phase Service

Same as Single Phase Service, except a three phase additional charge of $7.36 per month shall apply to Customers receiving three phase service.

Minimum Bill

$6.78 for Single Phase Service
$14.14 for Three Phase Service

The Company has the option to price service in the billing months of May and October at lower levels, which levels shall not be less than marginal cost. Any shoulder consumption remaining from October usage will be billed at the summer shoulder price in following billing months.

The summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day). All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

ADJUSTMENT FOR TRANSFORMER OWNERSHIP AND METERING

(a) When Company owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above schedule subject to a discount of 10.3¢ per kW per month of the billing demand each month.

(b) When Customer owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above schedule subject to a discount of 20.6¢ per kW per month of the billing demand each month.

(c) When Customer owns transformers and, at Company's option, energy is metered on secondary side of transformers, the demand shall be metered and the above schedule subject to a discount of 10.3¢ per kW per month of the billing demand each month.

TAX CLAUSE

To the charges computed under the above prices, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

Deleted:
Inserted: Heyman
Deleted: Steven J. Glaser
Deleted: Vice President, Rates and Regulatory Support
Deleted: July 1, 2000
Deleted: Entire Electric Service Area

RULES AND REGULATIONS

Service Connection Charges

1. There shall be a $13.50 charge for the initial establishment of each new service for each Customer.

2. There shall be a $13.50 charge for the re-establishment of each service for each Customer.

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this Schedule.

The Company may require a written contract and a minimum term of contract.

Optional price schedules are or may become available for certain classes of Customers. Upon application for service or upon request the Company will assist the Customer in selecting the price schedule best suited to the Customer's requirements, but the Company does not guarantee that Customers will be served under the most favorable price schedule. Upon written notification of any material changes in Customer's installation, load conditions, or use of service, Company will assist in determining if a change in price schedule is desirable, but not more than one such change in price schedule will be made within any twelve month period.

*This Schedule requires a type of meter not normally used; therefore, the Company makes no guarantee that the meters will be installed within any specific time. However, the Company will make its best effort to install the special meter within a reasonable time.

Deleted:
Inserted: Heyman
Deleted: Steven J. Glaser
Deleted: Vice President, Rates and Regulatory Support
Deleted: July 1, 2000
Deleted: Entire Electric Service Area

Pricing Plan GS-76N
General Service Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service	$ 9.00 per month
Customer Charge, Three Phase service	$16.00 per month

Energy Charges:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.098319	$0.062509	$0.048819
Next 54,500 kWh	$0.108319	$0.072509	$0.058819
55,000 kWh and above	$0.113319	$0.077509	$0.063819

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.087290	$0.037790
Next 54,500 kWh	$0.097290	$0.047790
55,000 kWh and above	$0.102290	$0.052790

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak: there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

Generation Capacity, all kWhs $0.000171 per kWh

Fuel and Purchased Power:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.061190	$0.025380	$0.011690
Next 54,500 kWh	$0.071190	$0.035380	$0.021690
55,000 kWh and above	$0.076190	$0.040380	$0.026690

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.050161	$0.000661
Next 54,500 kWh	$0.060161	$0.010661
55,000 kWh and above	$0.065161	$0.015661

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$2.12 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.23 per month
Customer Delivery	$2.85 per month

Note: Additional meter service charge of $7.00 per month for Three Phase Service.

Energy Charges:

Delivery:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.085228	$0.049418	$0.035728
Next 54,500 kWh	$0.095228	$0.059418	$0.045728
55,000 kWh and above	$0.100228	$0.064418	$0.050728

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.074199	$0.024699
Next 54,500 kWh	$0.084199	$0.034699
55,000 kWh and above	$0.089199	$0.039699

Fixed Must-Run (See Must-Run Generation – Rider No. 2) $0.003293 per kWh

System Benefits $0.000443 per kWh

Transmission $0.007298 per kWh

Transmission Ancillary Services

System Control & Dispatch $0.000099 per kWh
Reactive Supply and Voltage Control $0.000390 per kWh
Regulation and Frequency Response $0.000377 per kWh
Spinning Reserve Service $0.001024 per kWh
Supplemental Reserve Service $0.000167 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000171 per kWh

Fuel and Purchased Power:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.061190	$0.025380	$0.011690
Next 54,500 kWh	$0.071190	$0.035380	$0.021690
55,000 kWh and above	$0.076190	$0.040380	$0.026690

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.050161	$0.000661
Next 54,500 kWh	$0.060161	$0.010661
55,000 kWh and above	$0.065161	$0.015661

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:
- Must-Run Generation – Rider No. 2;
- Transmission and Ancillary Services – Rider No. 3;
- Termination Costs Regulatory Asset – Rider No. 4;
- Transmission Credit – Rider No. 5.

Pricing Plan GS-85A - ELIMINATED
Large General Service Time-of-Use

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises. Service under this Schedule shall be limited to a total of 30 MW.

APPLICABILITY

To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service. Customer shall contract for a demand of not less than 200 kW. Service under this Schedule shall commence when the appropriate meter has been installed.*

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

PRICE

Monthly net bills shall reflect the following prices plus any adjustments incorporated in this Schedule:

	BILLING MONTHS	
	Summer May-Oct.	Winter Nov.-Apr.
Customer Charge per Month	$98.01	$98.01
Demand Charge per Month		
On-peak demand All kW - per kW	$7.50	$4.96
Shoulder demand in excess of 150% of the On-peak demand - per kW	$4.96	N/A
Off-peak demand in excess of 150% of the On-peak demand - per kW	$3.75	$2.48

Deleted: July 1, 2000

Pricing Plan GS-85A - ELIMINATED
Large General Service Time-of-Use

	BILLING MONTHS	
	Summer May-Oct.	Winter Nov.-Apr.
Energy Charge		
On-Peak kWh	$0.069587	$0.065667
Shoulder kWh	$0.065667	N/A
Off-peak kWh	$0.061746	$0.057826

Excess shoulder demand is defined as that positive amount (if any) by which shoulder demand exceeds 150% of on-peak period demand.

Excess off-peak demand is defined as:

I. that positive amount by which off-peak period demand exceeds shoulder period demand (when and if shoulder period demand is greater than 150% of the on-peak period demand and off-peak period demand exceeds shoulder period demand), or;

II. that positive amount by which off-peak period demand exceeds 150% of the on-peak period demand (when and if shoulder period demand is less than 150% of the on-peak period demand and off-peak period demand exceeds 150% of the on-peak period demand), or;

III. zero when the above conditions in I are not met and the above conditions in II are not met.

In the event that excess shoulder and/or excess off-peak demand occur, excess shoulder demand shall be billed at the shoulder price and excess off-peak demand shall be billed at the off-peak price.

Any shoulder consumption remaining from October usage shall be billed at the summer shoulder price in following billing months.

The summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day). All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

BILLING DEMAND

The maximum 60-minute measured demand in the month, but not less than 50% of the maximum on-peak demand used for billing purposes in the preceding 11 months, nor less than 50% of the contract demand, nor less than 200 kW.

Deleted: July 1, 2000

ADJUSTMENT FOR TRANSFORMER OWNERSHIP AND METERING

(a) When Company owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above Schedule subject to a discount of 10.3¢ per kW per month of the billing demand each month.

(b) When Customer owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above Schedule subject to a discount of 20.6¢ per kW per month of the billing demand each month.

(c) When Customer owns transformers and, at Company's option, energy is metered on secondary side of transformers, the demand shall be metered and the above Schedule subject to a discount of 10.3¢ per kW per month of the billing demand each month.

TAX CLAUSE

To the charges computed under the above prices, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this Schedule.

The Company shall require a written contract and a minimum term of contract.

Optional price schedules are or may become available for certain classes of Customers. Upon application for service or upon request the Company will assist the Customer in selecting the price schedule best suited to the Customer's requirements, but Company does not guarantee that Customers will be served under the most favorable schedule. Upon written notification of any material changes in Customer's installation, load conditions, or use of service, the Company shall assist in determining if a change in schedule is desirable, but not more than one such change shall be made within any twelve month period.

*This Schedule requires a type of meter that is not normally used; therefore, the Company makes no guarantee that meters shall be installed within any specific time. However, the Company shall make its best effort to install the special meter within a reasonable time.

Deleted: July 1, 2000

Pricing Plan GS-85F (Frozen Rate) - ELIMINATED
Large General Service Time-of-Use

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises. Service under this Schedule shall be limited to a total of 30 MW. Service under this Schedule is available upon Customer's request through November 23, 1998. Customers not choosing this Schedule on or before November 23, 1998, shall be ineligible to choose this service after this date. Customers choosing this Schedule on or before November 23, 1998, shall be eligible for service hereunder, until this Schedule is terminated by Commission approval.

APPLICABILITY

To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service. Customer shall contract for a demand of not less than 200 kW. Service under this Schedule shall commence when the appropriate meter has been installed.*

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

PRICE

Monthly net bills shall reflect the following prices plus any adjustments incorporated in this Schedule:

	BILLING MONTHS	
	Summer May-Oct.	Winter Nov.-Apr.
Customer Charge per Month	$94.60	$94.60
Demand Charge per Month		
On-peak demand All kW - per kW	$16.34	$9.10
Shoulder demand in excess of 150% of the On-peak demand – per kW	$10.80	N/A
Off-peak demand in excess of 150% of the On-peak demand - per kW	$8.19	$4.54

Deleted: July 1, 2000

Pricing Plan GS-85F (Frozen Rate) - ELIMINATED
Large General Service Time-of-Use

	BILLING MONTHS	
	Summer May-Oct.	Winter Nov.-Apr.
Energy Charge		
On-Peak kWh	$0.104973	$0.076808
Shoulder kWh	$0.076808	N/A
Off-peak kWh	$0.031320	$0.031320

Excess shoulder demand is defined as that positive amount (if any) by which shoulder demand exceeds 150% of on-peak period demand.

Excess off-peak demand is defined as:

I. that positive amount by which off-peak period demand exceeds shoulder period demand (when and if shoulder period demand is greater than 150% of the on-peak period demand and off-peak period demand exceeds shoulder period demand), or;

II. that positive amount by which off-peak period demand exceeds 150% of the on-peak period demand (when and if shoulder period demand is less than 150% of the on-peak period demand and off-peak period demand exceeds 150% of the on-peak period demand), or;

III. zero when the above conditions in I are not met and the above conditions in II are not met.

In the event that excess shoulder and/or excess off-peak demand occur, excess shoulder demand shall be billed at the shoulder price and excess off-peak demand shall be billed at the off-peak price.

Any shoulder consumption remaining from October usage shall be billed at the summer shoulder price in following billing months.

The summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day). All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

BILLING DEMAND

The maximum 60-minute measured demand in the month, but not less than 50% of the maximum on-peak demand used for billing purposes in the preceding 11 months, nor less than 50% of the contract demand, nor less than 200 kW.

Deleted: July 1, 2000

ADJUSTMENT FOR TRANSFORMER OWNERSHIP AND METERING

(a) When Company owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above Schedule subject to a discount of 10.3¢ per kW per month of the billing demand each month.

(b) When Customer owns transformers and, at Company's option, energy is metered on secondary side of transformers, the demand shall be metered and the above Schedule subject to a discount of 10.3¢ per kW per month of the billing demand each month.

TAX CLAUSE

To the charges computed under the above prices, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this Schedule.

The Company shall require a written contract and a minimum term of contract.

Optional price schedules are or may become available for certain classes of Customers. Upon application for service or upon request the Company will assist the Customer in selecting the price schedule best suited to the Customer's requirements, but Company does not guarantee that Customers will be served under the most favorable schedule. Upon written notification of any material changes in Customer's installation, load conditions, or use of service, the Company shall assist in determining if a change in schedule is desirable, but not more than one such change shall be made within any twelve month period.

*This Schedule requires a type of meter that is not normally used; therefore, the Company makes no guarantee that meters shall be installed within any specific time. However, the Company shall make its best effort to install the special meter within a reasonable time.

Deleted: July 1, 2000

Pricing Plan GS-85N
General Service Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge $371.88 per month

Demand Charges:

On-peak $3.00 per kW
Off-peak $1.00 per kW

Energy Charges:

	SUMMER (May – October)	WINTER (November – April)
On-peak	$0.056992	$0.052310
Shoulder-peak	$0.041076	N/A
Off-peak	$0.035742	$0.031060

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak: there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

Generation Capacity, all kWhs $0.000171 per kWh

Fuel and Purchased Power:

	SUMMER (May – October)	WINTER (November – April)
On-peak	$0.072176	$0.060679
Shoulder-peak	$0.036366	N/A
Off-peak	$0.022676	$0.011179

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and jthe above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$223.13 per month
Meter Reading	$ 18.59 per month
Billing & Collection	$111.56 per month
Customer Delivery	$ 18.59 per month

Energy Charges:

Delivery:

On-peak	$3.00 per kW
Off-peak	$1.00 per kW

	SUMMER (May – October)	WINTER (November – April)
On-peak	$0.043901	$0.039219
Shoulder-peak	$0.027985	N/A
Off-peak	$0.022651	$0.017969

Fixed Must-Run (See Must-Run Generation – Rider No. 2) $0.003293 per kWh

System Benefits $0.000443 per kWh

Transmission $0.007298 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000171 per kWh

Fuel and Purchased Power:

	SUMMER (May – October)	WINTER (November – April)
On-peak	$0.072176	$0.060679
Shoulder-peak	$0.036366	N/A
Off-peak	$0.022676	$0.011179

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;
Transmission and Ancillary Services – Rider No. 3;
Termination Costs Regulatory Asset – Rider No. 4;
Transmission Credit – Rider No. 5.

Pricing Plan LLP-14 - ELIMINATED
Large Light and Power Service

AVAILABILITY

Rate No. 14 shall be available for any Customer within the service territory of the Company if the Company has facilities of adequate capacity and a written contract, covering such matters as the Company and Customer shall deem appropriate.

CHARACTER OF SERVICE

Service shall be three phase, 60 Hertz, and shall be supplied directly from any 46,000 volt, or higher voltage, system through distribution facilities used exclusively to serve Rate 14 customers at a delivery voltage of not less than 2400/4160 volts and delivered at a single point of delivery unless otherwise specified in the contract.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this rate schedule:

	BILLING MONTHS	
	Summer	Winter
Demand Charge	May-Oct.	Nov.-Apr.
Per kW of Billing Demand per month	$9.97	$9.97
Energy Charge		
All kWh @	$0.046001	$0.043701

BILLING DEMAND

The billing demand shall be specified in the contract, but shall not be less than 3,000 kW. Additionally, the billing demand shall not be less than 66.67% of the maximum billing demand in the preceding eleven (11) months, unless otherwise specified in the contract.

POWER FACTOR ADJUSTMENT

The above rate is subject to a discount or a charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is above or below 90% lagging to a maximum discount of 13.0¢ per kW of billing demand per month.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

Deleted: July 1, 2000

Pricing Plan LLP-90A - ELIMINATED
Large Light and Power Time-of-Use

AVAILABILITY

Price Schedule No. 90 shall be available for any Customer within the service territory of the Company if the Company has facilities of adequate capacity and a written contract, covering such matters as the Company and Customer shall deem appropriate. Service under this Schedule shall commence when the appropriate meter has been installed.*

CHARACTER OF SERVICE

Service shall be three phase, 60 Hertz, and shall be supplied directly from any 46,000 volt, or higher voltage, system through distribution facilities used exclusively to serve Price Schedule No. 90 customers at a delivery voltage of not less than 2400/4160 volts and delivered at a single point of delivery unless otherwise specified in the contract.

PRICE

Monthly net bills shall reflect the following prices plus any adjustments incorporated in this Schedule:

	BILLING MONTHS	
	Summer	Winter
Demand Charge per Month	May-Oct.	Nov.-Apr.
On-peak demand All kW - per kW	$10.95	$8.99
Shoulder demand in excess of 150% of the On-peak demand - per kW	$7.23	N/A
Off-peak demand in excess of 150% of the On-peak demand - per kW	$5.40	$4.42
Energy Charge		
On-Peak kWh	$0.058806	$0.058806
Shoulder kWh	$0.049005	N/A
Off-peak kWh	$0.041654	$0.041654

Excess shoulder demand is defined as that positive amount (if any) by which shoulder demand exceeds 150% of on-peak period demand.

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Excess off-peak demand is defined as:

I. that positive amount by which off-peak period demand exceeds shoulder period demand (when and if shoulder period demand is greater than 150% of the on-peak period demand and off-peak period demand exceeds shoulder period demand), or;
II. that positive amount by which off-peak period demand exceeds 150% of the on-peak period demand (when and if shoulder period demand is less than 150% of the on-peak period demand and off-peak period demand exceeds 150% of the on-peak period demand), or;
III. zero when the above conditions in I are not met and the above conditions in II are not met.

In the event that excess shoulder and/or excess off-peak demand occur, excess shoulder demand shall be billed at the shoulder price and excess off-peak demand shall be billed at the off-peak price.

Any shoulder consumption remaining from October usage shall be billed at the summer shoulder price in following billing months.

The summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day). All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

BILLING DEMAND

The billing demand shall be specified in the contract, but shall not be less than 3,000 kW. Additionally, the On-Peak billing demand shall not be less than 66.67% of the maximum On-Peak billing demand in the preceding eleven (11) months, unless otherwise specified in the contract.

POWER FACTOR ADJUSTMENT

Prices are subject to a discount or a charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is above or below 90% lagging to a maximum discount of 13.0¢ per kW of billing demand per month.

TAX CLAUSE

To the charges computed under the above prices, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

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RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this Schedule.

The Company shall require a written contract and a minimum term of contract.

Optional price schedules are or may become available for certain classes of Customers. Upon application for service or upon request the Company will assist the Customer in selecting the price schedule best suited to the Customer's requirements, but Company does not guarantee that Customers will be served under the most favorable schedule. Upon written notification of any material changes in Customer's installation, load conditions, or use of service, the Company shall assist in determining if a change in schedule is desirable, but not more than one such change shall be made within any twelve month period.

*This Schedule requires a type of meter that is not normally used; therefore, the Company makes no guarantee that meters shall be installed within any specific time. However, the Company shall make its best effort to install the special meter within a reasonable time.

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Pricing Plan LLP-90F (Frozen Rate) - ELIMINATED
Large Light and Power Time-of-Use

AVAILABILITY

Price Schedule No. 90 shall be available for any Customer within the service territory of the Company if the Company has facilities of adequate capacity and a written contract, covering such matters as the Company and Customer shall deem appropriate. Service under this Schedule shall commence when the appropriate meter has been installed.* Service under this Schedule is available upon Customer's request through November 23, 1998. Customers not choosing this Schedule on or before November 23, 1998, shall be ineligible to choose this service after this date. Customers choosing this Schedule on or before November 23, 1998, shall be eligible for service hereunder, until this Schedule is terminated by Commission approval.

CHARACTER OF SERVICE

Service shall be three phase, 60 Hertz, and shall be supplied directly from any 46,000 volt, or higher voltage, system through distribution facilities used exclusively to serve Price Schedule No. 90 customers at a delivery voltage of not less than 2400/4160 volts and delivered at a single point of delivery unless otherwise specified in the contract.

PRICE

Monthly net bills shall reflect the following prices plus any adjustments incorporated in this Schedule:

	BILLING MONTHS	
	Summer	Winter
Demand Charge per Month	May-Oct.	Nov.-Apr.
On-peak demand All kW - per kW	$20.34	$10.73
Shoulder demand in excess of 150% of the On-peak demand - per kW	$13.43	N/A
Off-peak demand in excess of 150% of the On-peak demand -per kW	$10.18	$5.38
Energy Charge		
On-Peak kWh	$0.083541	$0.042003
Shoulder kWh	$0.042003	N/A
Off-peak kWh	$0.028002	$0.028002

Excess shoulder demand is defined as that positive amount (if any) by which shoulder demand exceeds 150% of on-peak period demand.

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Excess off-peak demand is defined as:

I. that positive amount by which off-peak period demand exceeds shoulder period demand (when and if shoulder period demand is greater than 150% of the on-peak period demand and off-peak period demand exceeds shoulder period demand), or;

II. that positive amount by which off-peak period demand exceeds 150% of the on-peak period demand (when and if shoulder period demand is less than 150% of the on-peak period demand and off-peak period demand exceeds 150% of the on-peak period demand), or;

III. zero when the above conditions in I are not met and the above conditions in II are not met.

In the event that excess shoulder and/or excess off-peak demand occur, excess shoulder demand shall be billed at the shoulder price and excess off-peak demand shall be billed at the off-peak price.

Any shoulder consumption remaining from October usage shall be billed at the summer shoulder price in following billing months.

The summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day). All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

BILLING DEMAND

The billing demand shall be specified in the contract, but shall not be less than 3,000 kW. Additionally, the On-Peak billing demand shall not be less than 66.67% of the maximum On-Peak billing demand in the preceding eleven (11) months, unless otherwise specified in the contract.

POWER FACTOR ADJUSTMENT

Prices are subject to a discount or a charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is above or below 90% lagging to a maximum discount of 13.0¢ per kW of billing demand per month.

TAX CLAUSE

To the charges computed under the above prices, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

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RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this Schedule.

The Company shall require a written contract and a minimum term of contract.

Optional price schedules are or may become available for certain classes of Customers. Upon application for service or upon request the Company will assist the Customer in selecting the price schedule best suited to the Customer's requirements, but Company does not guarantee that Customers will be served under the most favorable schedule. Upon written notification of any material changes in Customer's installation, load conditions, or use of service, the Company shall assist in determining if a change in schedule is desirable, but not more than one such change shall be made within any twelve month period.

*This Schedule requires a type of meter that is not normally used; therefore, the Company makes no guarantee that meters shall be installed within any specific time. However, the Company shall make its best effort to install the special meter within a reasonable time.

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Pricing Plan LLP-90N
Large Light and Power Service Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

CHARACTER OF SERVICE
Service shall be three phase, 60 Hertz, Primary Service, and shall be supplied directly from any 46,000 volt, or higher voltage, system at a delivery voltage of not less than 13,800 volts and delivered at a single point of delivery unless otherwise specified in the contract.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge $500.00 per month

Demand Charges:
On-peak $8.00 per kW
Off-peak $2.66 per kW

Energy Charges:

	Summer (May – October)	Winter (November - April)
On-Peak	$0.032692	$0.028722
Shoulder-Peak	$0.023012	N/A
Off-Peak	$0.020192	$0.016222

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

_____On-Peak is 2:00 p.m. to 6:00 p.m.

_____Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

_____Off-Peak is 8:00 p.m. to 12:00 p.m.

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

_____On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

_____Shoulder-Peak: there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

Generation Capacity, all kWhs $0.000343 per kWh

Fuel and Purchased Power:

	Summer (May – October)	Winter (November - April)
On-Peak	$0.039680	$0.028840
Shoulder-Peak	$0.030000	N/A
Off-Peak	$0.027180	$0.035710

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

PRIMARY SERVICE

The above rate is subject to Primary Service and Metering. The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers

POWER FACTOR ADJUSTMENT

The above rate is subject to a discount or a charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is above or below 90% lagging to a maximum discount of 13.0¢ per kW of billing demand per month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$300.00 per month
Meter Reading	$025.00 per month
Billing & Collection	$150.00 per month
Customer Delivery	$025.00 per month

Energy Charges:

Delivery:

On-peak	$8.00 per kW
Off-peak	$2.66 per kW

	Summer (May – October)	Winter (November - April)
On-Peak	$0.020925	$0.016955
Shoulder-Peak	$0.011245	N/A
Off-Peak	$0.008425	$0.004455

Fixed Must-Run (See Must-Run Generation – Rider No. 2) $0.003408 per kWh

System Benefits $0.000433 per kWh

Transmission $0.006184 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000084 per kWh
Reactive Supply and Voltage Control	$0.000330 per kWh
Regulation and Frequency Response	$0.000320 per kWh
Spinning Reserve Service	$0.000867 per kWh
Supplemental Reserve Service	$0.000141 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000343 per kWh

Fuel and Purchased Power:

	Summer (May – October)	Winter (November - April)
On-Peak	$0.039680	$0.028840
Shoulder-Peak	$0.027180	N/A
Off-Peak	$0.030000	$0.035710

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;
Transmission and Ancillary Services – Rider No. 3;
Termination Costs Regulatory Asset – Rider No. 4;
Transmission Credit – Rider No. 5.

Pricing Plan PS-40
Municipal Service

AVAILABILITY

Available for Municipal Service where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

Applicable for service to the City of Tucson and City of South Tucson for Municipal buildings and grounds.

Not applicable to resale, breakdown, standby, or auxiliary service or to buildings used for residential purposes.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, at secondary voltage and subject to availability at point of delivery approved by the Company.

RATE

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges:	
Summer (May – October, all kWh	$0.061737
Winter (November – April), all kWh	$0.051737
Generation Capacity, all kWhs	$0.000312
Fuel and Purchased Power:	
Summer (May – October, all kWh	$0.035837
Winter (November – April), all kWh	$0.025837

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy Charges:	
Delivery:	
Summer (May – October, all kWh	$0.050158
Winter (November – April), all kWh	$0.040158
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003289 per kWh

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System Benefits	$0.000434 per kWh
Transmission	$0.006129 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000083 per kWh
Reactive Supply and Voltage Control	$0.000327 per kWh
Regulation and Frequency Response	$0.000317 per kWh
Spinning Reserve Service	$0.000860 per kWh
Supplemental Reserve Service	$0.000140 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Generation Capacity	$0.000312 per kWh
Fuel and Purchased Power:	
Summer (May – October, all kWh	$0.035837
Winter (November – April), all kWh	$0.025837

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

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ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

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Pricing Plan PS-41
Traffic Signal and Street Lighting Service

AVAILABILITY
Available for service to the State, a county, city, town, political subdivision, improvement district, or a responsible person or persons for unincorporated communities for Traffic Signal and Street Lighting purposes where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Applicable to Customer owned and maintained traffic signals and public street and highway lighting.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery approved by the Company.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

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BUNDLED STANDARD OFFER SERVICE

All kWh @ $0.050196 per kWh

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Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

Generation Capacity, all kWh	$0.0003163 per kWh
Fuel and Purchased Power, per kWh	$0.029484 per kWh

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BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Delivery	$0.013207 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.002305 per kWh
System Benefits	$0.000413 per kWh
Transmission	$0.026736 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000363 per kWh
Reactive Supply and Voltage Control	$0.001427 per kWh
Regulation and Frequency Response	$0.001383 per kWh
Spinning Reserve Service	$0.003750 per kWh
Supplemental Reserve Service	$0.000612 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity	$0.000163 per kWh
Fuel and Purchased Power:	$0.029484

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

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FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

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Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

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TAX CLAUSE¶
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.¶
¶
RULES AND REGULATIONS¶
The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this rate schedule.¶
¶
The Company may require a written contract.¶
¶
Where the Customer's utilization equipment is operated on a fixed schedule and can be readily and efficiently inspected by the Company to verify its demand and/or kWh usage, the Company may supply unmetered service under this Rate Schedule upon the basis of the demand and/or kWh usage determined by the Company. The Company reserves the right at any time to meter service previously supplied on an unmetered basis. The Customer will be responsible for notifying the Company of any changes being made in the equipment connected to the system. The determined demand and/or kWh usage will be adjusted as equipment is changed.¶

Pricing Plan PS-43
Municipal Water Pumping Service

AVAILABILITY
Available for service to the City of Tucson Water Utility and private water Companies where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Applicable for service to booster stations and wells used for domestic water supply.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as elected by Customer and subject to availability at point of delivery approved by the Company. Primary metering may be used by mutual agreement.

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges:		
Summer (May – October, all kWh		$0.061737
Winter (November – April), all kWh		$0.051737
Generation Capacity, all kWh		$0.000312
Fuel and Purchased Power:		
Summer (May – October, all kWs	$0.049500	
Winter (November – April), all kWh	$0.039500	

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy Charges:	
Delivery:	
Summer (May – October, all kWh	$0.050158
Winter (November – April), all kWh	$0.040158
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003289 per kWh
System Benefits	$0.000434 per kWh

Transmission	$0.006129 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000083 per kWh
Reactive Supply and Voltage Control	$0.000327 per kWh
Regulation and Frequency Response	$0.000317 per kWh
Spinning Reserve Service	$0.000860 per kWh
Supplemental Reserve Service	$0.000140 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Generation Capacity	$0.000312 per kWh
Fuel and Purchased Power:	
Summer (May – October, all kWh	$0.049500
Winter (November – April), all kWh	$0.039500

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TERMS AND CONDITIONS OF INTERRUPTIBLE SERVICE

1. Customer must furnish, install, own, and maintain at each point of delivery all necessary Company approved equipment which will enable the Company to interrupt service with its master control station.

2. Service may be interrupted by Company during certain periods of the day not exceeding six hours in any 24-hour period.

3. Company will endeavor to give Customer one hour notice of impending interruption; however, service may be interrupted without notice should Company deem such action necessary.

4. The interruptible load shall be separately served and metered and shall at no time be connected to facilities serving Customer's firm load. Conversely, the firm load shall be separately served and metered and shall at no time be connected to facilities serving Customer's interruptible load.

5. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan PS-50
Public Street Lighting Service

AVAILABILITY

Available for service for lighting public streets, alleys, thoroughfares, public parks, and playgrounds by use of Company's standard facilities where such service is contracted under this pricing plan by the state, a county, city, town, political subdivision, improvement district, or a responsible person or persons for unincorporated communities.

APPLICABILITY

Applicable to street lighting service from dusk to dawn and Company will own, operate, and maintain the street light system including lamps and globe replacements.

CHARACTER OF SERVICE

Multiple or series street lighting system at option of Company and at one standard nominal voltage.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
per unit per month	$9.56	$9.56	$9.56	$14.34	$22.13	$18.10	$3.34

Note:

The watt high pressure sodium lamps are charged per unit per month.

Per one pole addition and an extension of up to 100 feet of overhead service are charged per pole.

Underground Service is per 100 watt or less high pressure sodium lamp unit per month mounted on standard pole.

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Generation Capacity	$0.0027	$0.0034	$0.0049	$0.0122	$0.0196
Fuel & Purchased Power	$0.4874	$0.6203	$0.8862	$2.2154	$3.5447

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

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Per 55OH, 55UG, 55P watt high pressure sodium lamp unit per month $10.05¶
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Per 100 watt high pressure sodium lamp unit per month. $11.26 ¶
¶
Per 250 watt high pressure sodium lamp unit per month. $16.90 ¶
¶
Per 400 watt high pressure sodium lamp unit per month. $26.07 ¶
¶
Per one pole addition and an extension of up to 100 feet of¶
overhead service. $ 3.93 ¶
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STANDARD LAMP UNITS, OVERHEAD SERVICE

(1) The standard 100 watt lamp unit for overhead service is a 9,500 lumen high pressure sodium unit, mounted on a four foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 25 feet above ground level.

(2) The standard 250 watt lamp unit for overhead service is a 27,500 lumen high pressure sodium unit, mounted on an eight foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 27 feet above ground level.

(3) The standard 400 watt lamp unit for overhead service is a 50,000 lumen high pressure sodium unit, mounted on an eighteen foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 35 feet above ground level.

(4) The standard 100 watt lamp unit for underground service is a 9,500 lumen high pressure sodium post top unit mounted on a pole approximately 15 feet above ground level.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Delivery	$8.95	$8.78	$8.45	$0.12	$17.68
Fixed Must-Run	$0.04	$0.05	$0.07	$0.17	$0.28
System Benefits	$0.01	$0.01	$0.01	$0.03	$0.05
Transmission	$0.44	$0.56	$0.80	$2.01	$3.21
Transmission Ancillary					
System Control & Load Dispatch	$0.01	$0.01	$0.01	$0.03	$0.04
Reactive Supply and Voltage Control	$0.02	$0.03	$0.04	$0.12	$0.17
Regulation and Frequency Response	$0.02	$0.03	$0.04	$0.10	$0.17
Spinning Reserve Service	$0.06	$0.08	$0.11	$0.28	$0.45
Supplemental Reserve Service	$0.01	$0.01	$0.02	$0.05	$0.07
Energy Imbalance Service: currently charged pursuant to the Company's OATT.					
Generation Capacity:	$0.01	$.01	$0.01	$0.01	$0.02
Fuel and Purchased Power	$0.49	$0.62	$0.89	$2.22	$3.54

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

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FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

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SPECIAL PROVISIONS

(1) Installation of a light on an existing pole is subject to prior approval of Company.

(2) For underground service, where customer provides trenching up to 10 feet in accordance with Company's electric service requirements, customer shall be billed at the rates for overhead service.

(3) Extensions beyond 100 feet and all installations other than those addressed in this pricing plan will require specific agreements providing adequate revenue or arrangements for construction financing.

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(4) The Customer is not authorized to make connections to this lighting circuit or to make attachments or alterations to the Company owned pole.

(5) If a Customer requests a relocation of a lighting installation, the costs of such relocation must be borne by the Customer.

(6) The Customer is expected to notify the Company when lamp outages occur.

(7) The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

(8) After the minimum contract period, if any, has expired, this agreement shall be extended from year to year unless written notice of desire to terminate is given by either party at least thirty (30) days prior to the end of any such annual extension date.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

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ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

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Pricing Plan GS-51
Private Street and Area Lighting Service

AVAILABILITY
At any point where the Company in its judgment has facilities of adequate capacity and suitable voltage available.

APPLICABILITY
To any Customer for private street or outdoor area lighting where this service can be supplied from existing facilities of the Company.

Service is from dusk to dawn and the Company will install, own, operate, and maintain the complete lighting installation including lamp replacements.

Not applicable to resale service.

CHARACTER OF SERVICE
Multiple or series street lighting system at option of Company and at one standard nominal voltage.

BUNDLED STANDARD OFFER SERVICE

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
per unit per month	$9.56	$9.56	$9.56	$14.34	$22.13	$18.10	$3.34

Note:

The watt high pressure sodium lamps are charged per unit per month.

Per one pole addition and an extension of up to 100 feet of overhead service are charged per pole.

Underground Service is per 100 watt or less high pressure sodium lamp unit per month mounted on standard pole.

Generation Capacity:	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
Fuel and Purchased Power	$0.0027	$9.56	$9.56	$14.34	$22.13	$18.10	$3.34

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

STANDARD LAMP UNITS, OVERHEAD SERVICE

(1) The standard 100 watt lamp unit for overhead service is a 9,500 lumen high pressure sodium unit, mounted on a four foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 25 feet above ground level.

(2) The standard 250 watt lamp unit for overhead service is a 27,500 lumen high pressure sodium unit, mounted on an eight foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 27 feet above ground level.

(3) The standard 400 watt lamp unit for overhead service is a 50,000 lumen high pressure sodium unit, mounted on an eighteen foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 35 feet above ground level.

(4) The standard 100 watt lamp unit for underground service is a 9,500 lumen high pressure sodium post top unit mounted on a pole approximately 15 feet above ground level.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Delivery	$8.95	$8.78	$8.45	$0.12	$17.68
Fixed Must-Run	$0.04	$0.05	$0..07	$0.17	$0.28
System Benefits	$0.01	$0.01	$0.01	$0.03	$0.05
Transmission	$0.44	$0.56	$0.80	$2.01	$3.21
Transmission Ancillary					
System Control & Load Dispatch	$0.01	$0.01	$0.01	$0.03	$0.04
Reactive Supply and Voltage Control	$0.02	$0.03	$0.04	$0.12	$0.17
Regulation and Frequency Response	$0.02	$0.03	$0.04	$0.10	$0.17
Spinning Reserve Service	$0.06	$0.08	$0.11	$0.28	$0.45
Supplemental Reserve Service	$0.01	$0.01	$0.02	$0.05	$0.07
Energy Imbalance Service: currently charged pursuant to the Company's OATT.					
Generation Capacity:	$0.01	$.01	$0.01	$0.01	$0.02
Fuel and Purchased Power	$0.49	$0.62	$0.89	$2.22	$3.54

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

SPECIAL PROVISIONS

(1) Installation of a light on an existing pole is subject to prior approval of Company.

(2) For underground service, where customer provides trenching up to 10 feet in accordance with Company's electric service requirements, customer shall be billed at the rates for overhead service.

(3) Extensions beyond 100 feet and all installations other than those addressed in this pricing plan will require specific agreements providing adequate revenue or arrangements for construction financing.

(4) The Customer is not authorized to make connections to this lighting circuit or to make attachments or alterations to the Company owned pole.

(5) If a Customer requests a relocation of a lighting installation, the costs of such relocation must be borne by the Customer.

(6) The Customer is expected to notify the Company when lamp outages occur.

(7) The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

(8) After the minimum contract period, if any, has expired, this agreement shall be extended from year to year unless written notice of desire to terminate is given by either party at least thirty (30) days prior to the end of any such annual extension date.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Rider 79
Pricing Flexibility Rider

AVAILABILITY

Available to commercial and industrial customers qualifying for electric service under any commercial or industrial pricing plan. For purposes of determining a negotiated pricing structure ("negotiated price") for a customer pursuant to this rider, the Company and the customer shall specify a pricing plan under which the customer would be entitled to receive service ("Comparative Pricing Plan"). Availability shall be subject to the Terms and Conditions specified herein.

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TERMS AND CONDITIONS OF SERVICE

1. The negotiated price must cover the Company's marginal cost, considering the expected term or duration of service and the type of service offered.

2. The negotiated price cannot exceed the Comparative Pricing Plan price.

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3. A customer must document a viable alternative to receiving service under the Comparative Pricing Plan.

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4. The negotiated price must be commensurate with the cost to the customer of that customer's alternative(s).

5. The customer must agree to an energy audit unless the customer has recently completed a significant DSM program or energy audit and provides the Company with adequate documentation concerning the DSM activities or audit.

6. Each service under this rider shall be evidenced by a contract. The contract may be for varying lengths of time as determined by individual customer or Company requirements. Each executed contract shall be filed with the Commissioners, Staff and RUCO, on a confidential basis, at least 30 days prior to the effective date of the proposed contract and Staff shall determine whether the contract complies with the pricing plan prior to the effective date. Staff shall be provided with adequate documentation and support of each term listed in this rider (e.g., the customer's alternatives) before the 30-day review period commences. If the negotiated contract complies with the tariff, the contract would not be submitted to the Commission for approval, unless a Commissioner requests a formal vote. The Company and Staff may agree on standardized contracts for qualifying customers under 200 kW. To the extent that negotiated contract elements adhere to such a standardized contract, the Company may implement the negotiated elements without Commission approval, unless a Commissioner requests a formal vote. The Company shall notify Staff and RUCO of such contracts by providing a term sheet acceptable to TEP, Staff and RUCO.

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7. The Company's shareholders shall be responsible for any foregone revenue resulting from the rider.

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8. The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate schedule.

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Rider 2
Must-Run Generation

Variable Component	$ 0.015000 per kWh
Fixed Component	
Residential Service	$ 0.005017 per kWh
General Service - Rates No. 10 and 76	0.005493 per kWh
Mobile Home Parks - Rate No. 11	0.006549 per kWh
Interruptible Agricultural Pumping - Rate No. 31	0.003752 per kWh
Large General Service - Rates No. 13, 85 and 85A	0.003787 per kWh
Large Light & Power - Rates No. 14, 90, and 90A	0.002900 per kWh
Lighting - Rates No. 41, 50 and 51	0.004522 per kWh
Public Authority - Rates No. 40 and 43	0.004876 per kWh
(Weighted Average Fixed Component)	$ 0.004320 per kWh

Variable component is billed to scheduling coordinator based on actual must-run energy delivered.
Fixed component is billed directly to end-use customer.

During a month in which must-run generation is provided to meet retail load, the Market Price component used in calculating the on-peak MGC shall be a weighted average of the Palo Verde NYMEX futures price and the must-run variable cost charges that are levied on scheduling coordinators serving retail customers in the TEP load zone during that month, consistent with AISA protocols.

Rider 3
Transmission & Ancillary Services

Transmission

Group "A" : For customers under 20 kW and not demand metered.

Applicability: Required for Direct Access Service pursuant to the Company's OATT. The rates in Transmission Credit -- Rider No. 5 will be used for the Transmission Credit in the calculation of the floating CTC. These rates are based on the Company's OATT, but are converted to a kWh-basis for specific load-profiled customer groups. For illustrative purposes, estimated rates are shown in selected Direct Access tariffs.

Note: A loss factor adjustment shall be made for transmission and ancillary services.

Group "B" : For customers not in Group A.

Applicability: Required for Direct Access Service pursuant to the Company's OATT. The following OATT rate is shown below for information and for calculation of the floating CTC (See Transmission Rider No. 3).

As of June 7, 1999, the transmission charges are as follows:

EHV	Non-EHV	
2.259	$0.757000	per kW / Month

Note: A loss factor adjustment shall be made for transmission and ancillary services.

Ancillary Services

Group "A" : For customers under 20 kW and not demand metered.

Applicability: Required for Direct Access Service, but not purchased directly by the customer. Sold to scheduling coordinator pursuant to the OATT. The rates in Transmission Credit -- Rider No. 5 will be used for the Transmission Credit in the calculation of the floating CTC. These rates are based on the Company's OATT, but are converted to a kWh-basis for specific load-profiled customer groups. For illustrative purposes, estimated rates are shown in selected Direct Access tariffs.

Services covered:

1. System Control & Dispatch
2. Reactive Supply and Voltage Control
3. Regulation and Frequency Response
4. Energy Imbalance Service
5. Spinning Reserve Service
6. Supplemental Reserve Service

Rider 3
Transmission & Ancillary Services

Notes:
- A loss factor adjustment shall be made for transmission and ancillary services.
- Energy Imbalance Service currently charged pursuant to the Company's OATT, which is subject to change pursuant to AISA protocols.

Group "B" : For customers not in Group A.

Applicability: Required for Direct Access Service pursuant to the Company's OATT. The following OATT rates are shown below for information and for calculation of the floating CTC (See Transmission Rider No. 3).

As of June 7, 1999, the charges are as follows:

Service		
System Control & Dispatch	$0.041000	per kW / Month
Reactive Supply and Voltage Control	$0.161000	per kW / Month
Regulation and Frequency Response	$0.156000	per kW / Month
Energy Imbalance Service	(see note)	
Spinning Reserve Service	$0.423000	per kW / Month
Supplemental Reserve Service	$0.069000	per kW / Month

Notes:
- A loss factor adjustment shall be made for transmission and ancillary services.
- Energy Imbalance Service currently charged pursuant to the Company's OATT, which is subject to change pursuant to AISA protocols.

Rider 4
Termination Costs Regulatory Asset Charge ("TCRAC")

The TCRAC for the period January 1, 2009 through December 31, 2009 shall be $0.012622 per kWh, applicable to all retail Customers.

Notes

1. The planned amortization schedule for the Termination Costs Regulatory Asset is contained in the Calculation of Termination Cost Regulatory Asset Charge, filed with the Commission July 2, 2007, as Exhibit KCG-2 to the direct testimony of Mr. Kentton Grant ("Termination Costs Regulatory Asset Amortization Schedule"). The actual amortization of the Termination Costs Regulatory Asset will depend on actual retail kWh sales.

2. To the extent that actual retail kWh sales in a given year are higher than the projected retail kWh sales for that year, the amortization attributed to that year will be increased, decreasing the unamortized balance of cost that remains to be collected.

3. To the extent that actual retail kWh sales in a given year are lower than the projected retail kWh sales for that year, the amortization attributed to that year will be less than the amount shown in the Calculation of Termination Cost Regulatory Asset Charge, resulting in a higher unamortized balance than would have occurred if sales were as projected.

4. Large Light and Power Service customers with contracts at negotiated rates will be assessed the TCRAC and recorded by the Company. Payment of such TCRAC assessments shall be arranged between the Company and Customer upon expiration of the current contract.

Rider 5
Transmission Cost Adjustment Charge ("TCAC")

The Transmission Cost Adjustment Charge ("TCAC") shall apply to all of the Company's retail pricing plans. All provisions of the applicable pricing plan will apply in addition to the TCAC authorized by this Rider.

Pricing plans to which the TCAC applies include transmission and ancillary service components listed in the table below. The listed transmission and ancillary service components are based on the Company's Federal Energy Regulatory Commission ("FERC") - approved Open Access Transmission Tariff ("OATT"). The listed transmission and ancillary service components are calculated on a volumetric basis by class of service.

Pursuant to this Rider, the TCAC, which is an annual adjustment to the transmission and ancillary service components, will be submitted to the Commission for review. In the event that the Company's FERC-approved OATT changes, TEP will file an additional recalculated TCAC, unless the regular annual adjustment addresses the OATT change. The TCAC is based upon the prior year's annual Transmission and Ancillary Service costs and retail energy sales. Transmission and Ancillary Service costs are calculated by applying the Company's approved OATT rates to TEP's retail jurisdictional sales. This TCAC will be applied volumetrically to kilowatt-hour sales under applicable electric pricing plans. The TCAC applies to all system sales and will not vary by class of service.

The initial transmission and ancillary service components of retail rates and are as follows:

	Residential	General Service	Lg Light & Power	Lighting	Public Authority
Transmission	$0.006950	$0.006740	$0.005711	$0.024692	$0.005660
Ancillary Services					
System Control - Load Dispatch	$0.000094	$0.000092	$0.000078	$0.000336	$0.000077
Reactive Supply and Voltage Control	$0.000371	$0.000360	$0.000305	$0.001318	$0.000302
Regulation and Frequency Response	$0.000359	$0.000349	$0.000295	$0.001277	$0.000293
Spinning Reserve Service	$0.000975	$0.000945	$0.000801	$0.003463	$0.000794
Supplemental Reserve Service	$0.000159	$0.000154	$0.000131	$0.000565	$0.000130

Note: All values presented as $/kWh

Rider 6 - ELIMINATED
Environmental Portfolio Surcharge

APPLICABILITY

The Environmental Portfolio Surcharge (EPS) applies to all customers in all territory served by Tucson Electric Power Company as mandated by the Arizona Corporation Commission.

SURCHARGE

The Environmental Portfolio Surcharge shall be applied to all monthly net bills at the following rates:

All kWh	$0.000875	*per kWh*

SURCHARGE LIMITS

The monthly total Environmental Portfolio Surcharge shall not exceed the following limits:

Residential Customers	$0.35	*per service per month*
Non-Residential Customers	$13.00	*per service per month**
Non-Residential Customers with demand of 3,000 kW or higher per month for three consecutive months	$39.00	*per service per month**

* The EPS will not be assessed to reactive meters or accumulators.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this rate schedule.

Customer bills shall reflect a line item entitled "Environmental Portfolio Surcharge, mandated by the Corporation Commission."

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RIDER 17
GreenWatts PRICING PLAN

AVAILABILITY/APPLICABILITY

GreenWatts is a Pricing Plan available to all Customers in all territory served by Tucson Electric Power Company at all points where facilities of the Company are of adequate capacity and are adjacent to the premises.

PRICING PLAN

A participating Customer under the *GreenWatts* Pricing Plan will be charged a monthly before-tax premium to the Customer's existing TEP Pricing Plan according to the following schedule:

First twenty-kWh block of energy @	$2.00
Each additional twenty-kWh block of energy @	$1.50

The number of twenty-kWh blocks purchased is at the discretion of the *GreenWatts* Customer and is subject to the conditions of service described below.

CONDITIONS OF SERVICE

- Revenues from *GreenWatts* will be devoted to the cost of building, operating, and maintaining new solar power sources in the State of Arizona.
- The total kWh under subscription cannot exceed the Customer's minimum monthly consumption during the prior twelve months. For a Customer with an insufficient billing history, subscription is limited to a total of four twenty-kWh blocks per month.
- The *GreenWatts* Customer is responsible for the premium payment for the subscribed number of blocks, regardless of the level of consumption in any given billing period.
- Customer must contact TEP to cancel or change subscriptions to *GreenWatts*. Any change or cancellation of subscription shall take effect in the succeeding billing period.
- All provisions of the Customer's current applicable rate schedule will apply during service under *GreenWatts*.
- Energy provided under *GreenWatts* will be generated by landfill gas from Tucson area landfills, displacing the burning of coal in a Tucson area power plant, and will be blended with solar power sources as solar power sources are constructed. The total amount of energy sold under *GreenWatts* shall not exceed the combined capacity of TEP's landfill gas facilities and solar power sources.
- Energy generated for *GreenWatts* will be delivered to TEP's distribution grid for general distribution.
- The premium charged for *GreenWatts* does not represent the sale or lease of generation assets.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

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To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.¶

Rider 84
Interruptible Service Rider

AVAILABILITY

Available to customers receiving and qualifying for electric service under pricing plans applicable to service over 200 kW.

CHARACTER OF SERVICE

Must meet all service requirements for the applicable pricing plan.

DISCOUNT

Customers that elect service under this rider will receive a credit (discount) on their bills.

TERMS AND CONDITIONS OF SERVICE

1. A customer qualifying for service as a Large Light & Power customer (greater than or equal to 3000 kW) service shall contract for a demand of not less than 1,000 kW; a customer qualifying as a Large General Service (greater than or equal to 200 kW but less than 3,000 kW) shall contract for a demand of not less than 200 kW.

2. The customer must give the Company three years' notice to convert interruptible load to firm load.

3. Customers that elect service under this rider will receive a credit (discount) on their bills. The discount, the maximum number of interruptions per year, the time interval in which customer must comply with Company's request for load reduction, the penalty for customer's failure to comply, and the term of contract will be negotiated on a customer by customer basis.

4. The interruptible load shall be served and metered as provided for in the contract.

5. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

6. The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate schedule.

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EXHIBIT

DBE-4

CLEAN VERSION

Tucson Electric Power
The Energy People

Pricing Plan R-01 FROZEN
Residential Electric Service

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single phase or three phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter; however, electric water heating may be metered separately.

Not applicable to resale, breakdown, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, nominal 120/240 volts.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service $ 9.00 per month

Customer Charge, Three Phase service $15.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.045818	$0.040818
Next 3,000 kWh	$0.055818	$0.050818
3,501 kWh and above	$0.060818	$0.055818

_____Generation Capacity, all kWh $0.000335 per kWh

_____Fuel and Purchased Power:

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.037621	$0.032621
Next 3,000 kWh	$0.047621	$0.042621
3,501 kWh and above	$0.052621	$0.047621

Tucson Electric Power
The Energy People

Pricing Plan R-01 FROZEN
Residential Electric Service

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.55 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.25 per month
Customer Delivery	$3.40 per month

Note: Additional meter service charge of $6.00 per month for Three Phase Service.

Energy (kWh) and Demand Charges (kW):

Delivery

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.031888	$0.026888
Next 3,000 kWh	$0.041888	$0.036888
3,501 kWh and above	$0.046888	$0.041888

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003822 per kWh
System Benefits	$0.000463 per kWh
Transmission	$0.007525 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity	$0.000335 per kWh

Fuel and Purchased Power

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.037621	$0.032621
Next 3,000 kWh	$0.047621	$0.042621
3,501 kWh and above	$0.052621	$0.047621

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Deleted: tariff

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan R-02 FROZEN
Residential Electric Water Heating Service

AVAILABILITY
This rate is limited to installations and customers served under Pricing Plan No. 2 on the effective date of this pricing plan sheet.

APPLICABILITY
To separately metered single phase residential off-peak water heating service where general residential service is also provided under Pricing Plan No. 1. When service under Pricing Plan No. 2 is discontinued, the Company will either combine usage and bill under Pricing Plan No. 1 or modify the service entrance equipment so all service is supplied through the Pricing Plan No. 1 meter.

Not applicable to three phase service, resale, breakdown, standby, auxiliary, or any other service except off-peak water heating in accordance with the provisions of this pricing plan.

Where service other than water heating to which this rate is applicable has been taken hereunder, the regular rate for such service shall be applied on a monthly basis to all consumption billed hereunder during the previous twelve months, less the aggregate of payments made hereunder for the same period of time. The regular rate shall continue to apply until the unauthorized service is permanently separated from the off-peak water heating service.

CHARACTER OF SERVICE
Single phase, 60 Hertz, nominal 120/240 volts.

Service may be controlled by the Company by disconnecting electricity during certain periods of the day not exceeding 8 hours in any 24-hour period, as determined by the Company from time to time.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges:

Delivery, all kWh	$0.050000 per kWh
Generation Capacity, all kWh	$0.000335 per kWh
Fuel and Purchased Power, all kWh	$0.044362 per kWh

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

Pricing Plan R-02 FROZEN
Residential Electric Water Heating Service

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy:

Delivery	$0.036070 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003822 per kWh
System Benefits	$0.000463 per kWh
Transmission	$0.007525 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity	$0.000335 per kWh
Fuel and Purchased Power	$0.044362 per kWh

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

The electric water heating equipment and installation shall conform to the Company's requirements and be for normal domestic use. The heater shall be of the storage type and not less than 30-gallon capacity. For a water heater equipped with one heating element, the rating of the heating element shall not exceed 6,000 watts. For a water heater equipped with more than one heating element, the rating of any such heating element shall not exceed 6,000 watts, and, if the total of the ratings of the elements exceeds 6,000 watts, they shall be thermostatically interlocked so that they cannot operate simultaneously and thereby exceed 6,000 watts. The Customer shall provide the necessary wiring to permit the installation of the Company's metering and control equipment.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Tucson Electric Power
The Energy People

Pricing Plan R-70N
Residential Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Service is available to individual private dwellings and individually metered multi-family units when all service is supplied at one point of delivery and energy is metered through one meter; however, controlled off-peak electric water heating may be metered separately.

Not applicable to three phase service, resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

Service under this pricing plan will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
Single phase, 60 Hertz, nominal 120/240 volts.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge: $9.00 per month

Energy Charges:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.081084	$0.046780	$0.031584
Next 3,000 kWh	$0.091084	$0.056780	$0.041584
3,501 kWh and above	$0.096084	$0.061780	$0.046584

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.068745	$0.019245
Next 3,000 kWh	$0.078745	$0.029245
3,501 kWh and above	$0.083745	$0.034245

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak: there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

If a Summer or Winter holiday falls on Saturday, the preceding Friday is designated off-peak; if a holiday falls on Sunday, the following Monday is designated off-peak.

Energy Charges continued:

Generation Capacity $0.000335 per kWh

Fuel and Purchased Power:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.072887	$0.038583	$0.023387
Next 3,000 kWh	$0.082887	$0.048583	$0.033387
3,501 kWh and above	$0.087887	$0.053583	$0.038387

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.060548	$0.011048
Next 3,000 kWh	$0.070548	$0.021048
3,501 kWh and above	$0.075548	$0.026048

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.55 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.25 per month
Customer Delivery	$3.40 per month

Note: Additional meter service charge of $6.00 per month for Three Phase Service.

Tucson Electric Power
The Energy People

Pricing Plan R-70N
Residential Time-of-Use

Energy:

Delivery

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.067154	$0.032850	$0.017654
Next 3,000 kWh	$0.077154	$0.042850	$0.027654
3,501 kWh and above	$0.082154	$0.047850	$0.032654

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.054815	$0.005315
Next 3,000 kWh	$0.064815	$0.015315
3,501 kWhs and above	$0.069815	$0.020315

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003822 per kWh
System Benefits	$0.000463 per kWh
Transmission	$0.007525 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Generation Capacity	$0.000335 per kWh

Fuel and Purchased Power:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.072887	$0.038583	$0.023387
Next 3,000 kWh	$0.082887	$0.048583	$0.033387
3,501 kWh and above	$0.087887	$0.053583	$0.038387

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.060548	$0.011048
Next 3,000 kWh	$0.070548	$0.021048
3,501 kWh and above	$0.075548	$0.026048

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plans:
R-201A FROZEN,
R-201BN AND R-201CN
Special Residential Electric Service

AVAILABILITY
Throughout the entire area where facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To single phase electric service in individual residences as described in current program details when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this Schedule requires that the customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below and that the customer's home conform to the standards of the Heating, Cooling and Comfort Guarantee program as in effect at the time of subscription to this Schedule. Notwithstanding the above, the customer's use of solar energy for any purpose shall not preclude subscription to this Schedule. Two different Options are available under this Schedule: BN, & CN. Subscription eligibility requirements are as follows:

Option A: This option is FROZEN to new customers.
Option BN: Customer must meet above conditions and must purchase under the time-of-use structure.
Option CN: Customer must meet above conditions and must use either (i.) solar equipment for water heating requirements during the year or (ii.) an electric heat pump water heater, or both (i.) and (ii.), and must purchase under the time-of-use structure applicable to Option CN.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
Single phase, 60 Hertz, nominal 120/240 volts.

PRICE UNDER OPTION A
A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Minimum Customer Charge $ 9.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.053500	$0.048500	$0.046000
Next 3,000 kWh	$0.063500	$0.058500	$0.056000
3,501 kWh and above	$0.068500	$0.063500	$0.061000

Generation Capacity, all kWh $0.000335 per kWh

Fuel and Purchase Power:

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.025640	$0.020640	$0.018140
Next 3,000 kWh	$0.035640	$0.030640	$0.028140
3,501 kWh and above	$0.040640	$0.035640	$0.033140

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

PRICE UNDER OPTION BN

A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Minimum Customer Charge $ 9.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.054100	$0.044100	$0.039100
Next 3,000 kWh	$0.064100	$0.054100	$0.049100
3,501 kWh and above	$0.059100	$0.049100	$0.044100

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.049100	$0.039100	$0.034100
Next 3,000 kWh	$0.059100	$0.049100	$0.044100
3,501 kWh and above	$0.054100	$0.044100	$0.039100

The Mid-Summer and Remaining Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day:

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.
Off-Peak is 8:00 p.m. to 12:00 p.m.
On-Peak is 2:00 p.m. to 6:00 p.m.

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.046600	$0.041600
Next 3,000 kWh	$0.056600	$0.051600
3,501 kWh and above	$0.051600	$0.046600

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day:

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: there are no shoulder peak periods in the winter.
Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

If a Summer or Winter holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

Energy Charges continued:

Generation Capacity $0.000335 per kWh

Fuel and Purchased Power:

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.031240	$0.021240	$0.016240
Next 3,000 kWh	$0.041240	$0.031240	$0.026240
3,501 kWh and above	$0.036240	$0.026240	$0.021240

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.026240	$0.016240	$0.011240
Next 3,000 kWh	$0.036240	$0.026240	$0.021240
3,501 kWh and above	$0.031240	$0.021240	$0.016240

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.023740	$0.018740
Next 3,000 kWh	$0.033740	$0.028740
3,501 kWh and above	$0.028740	$0.023740

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchase Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

PRICE UNDER OPTION CN

A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Minimum Customer Charge $ 9.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.053018	$0.043218	$0.038318
Next 3,000 kWh	$0.062818	$0.053018	$0.048118
3,501 kWh and above	$0.057918	$0.048118	$0.043218

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.048118	$0.038318	$0.033418
Next 3,000 kWh	$0.057918	$0.048118	$0.043218
3,501 kWh and above	$0.053018	$0.043218	$0.038318

The Mid-Summer and Remaining Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day:

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.
Off-Peak is 8:00 p.m. to 12:00 p.m.
On-Peak is 2:00 p.m. to 6:00 p.m.

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.045668	$0.040768
Next 3,000 kWh	$0.055468	$0.050568
3,501 kWh and above	$0.0450568	$0.045668

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day:

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak – there are no shoulder peak periods in the winter.
Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

If a Summer or Winter holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

Energy Charges continued:

Generation Capacity $0.000335 per kWh

Fuel and Purchase Power:

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.029823	$0.020023	$0.015123
Next 3,000 kWh	$0.039623	$0.029823	$0.024923
3,501 kWh and above	$0.034723	$0.024923	$0.020023

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.024923	$0.015123	$0.010223
Next 3,000 kWh	$0.034723	$0.024923	$0.020023
3,501 kWh and above	$0.029823	$0.020023	$0.015123

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.022473	$0.017573
Next 3,000 kWh	$0.032273	$0.027373
3,501 kWh and above	$0.027373	$0.022473

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchase Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE R-201A FROZEN, R-201BN AND R201CN CONSIST OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.55 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.25 per month
Customer Delivery	$3.40 per month

Note: Additional meter service charge of $6.00 per month for Three Phase Service.

Pricing Plans:
R-201A FROZEN,
R-201BN AND R-201CN
Special Residential Electric Service

Energy:

Delivery **(FOR OPTION A ONLY)**:

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.039570	$0.0345700038	$0.032070
Next 3,000 kWh	$0.049570	$0.044570	$0.042070
3,501 kWh and above	$0.054570	$0.049570	$0.047070

Delivery **(FOR OPTION BN ONLY)**:

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.040170	$0.030170	$0.025170
Next 3,000 kWh	$0.050170	$0.040170	$0.035170
3,501 kWh and above	$0.045170	$0.035170	$0.030170

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.035170	$0.025170	$0.020170
Next 3,000 kWh	$0.045170	$0.035170	$0.030170
3,501 kWh and above	$0.040170	$0.030170	$0.025170

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.032670	$0.027670
Next 3,000 kWh	$0.042670	$0.037670
3,501 kWh and above	$0.037670	$0.032670

Delivery **(FOR OPTION CN ONLY)**:

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.039088	$0.029288	$0.024388
Next 3,000 kWh	$0.048888	$0.039088	$0.034188
3,501 kWh and above	$0.043988	$0.034188	$0.029288

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.034188	$0.024388	$0.019488
Next 3,000 kWh	$0.043988	$0.034188	$0.029288
3,501 kWh and above	$0.039088	$0.029288	$0.024388

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.031738	$0.026838
Next 3,000 kWh	$0.041538	$0.036638
3,501 kWh and above	$0.036638	$0.031738

Fixed Must-Run (See Must-Run Generation – Rider No. 2) $0.003822 per kWh

System Benefits $0.000463 per kWh

Transmission $0.007525 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000335 per kWh

Fuel and Purchased Power:

(FOR OPTION A ONLY):

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.025640	$0.018140	$0.020640
Next 3,000 kWh	$0.035640	$0.028140	$0.030640
3,501 kWh and above	$0.040640	$0.033140	$0.035640

(FOR OPTION BN ONLY):

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.031240	$0.021240	$0.016240
Next 3,000 kWh	$0.041240	$0.031240	$0.026240
3,501 kWh and above	$0.036240	$0.026240	$0.021240

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.026240	$0.016240	$0.011240
Next 3,000 kWh	$0.036240	$0.026240	$0.021240
3,501 kWh and above	$0.031240	$0.021240	$0.016240

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.023740	$0.018740
Next 3,000 kWh	$0.033740	$0.028740
3,501 kWh and above	$0.028740	$0.023740

(FOR OPTION CN ONLY):

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.039088	$0.029288	$0.024388
Next 3,000 kWh	$0.048888	$0.039088	$0.034188
3,501 kWh and above	$0.043988	$0.034188	$0.029288

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.034188	$0.024388	$0.019488
Next 3,000 kWh	$0.043988	$0.034188	$0.029288
3,501 kWh and above	$0.039088	$0.029288	$0.024388

Pricing Plans:
R-201A FROZEN,
R-201BN AND R-201CN
Special Residential Electric Service

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.031738	$0.026838
Next 3,000 kWh	$0.041538	$0.036638
3,501 kWh and above	$0.036638	$0.031738

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Tucson Electric Power
The Energy People

Pricing Plan GS-10 FROZEN
General Service

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service $ 9.00 per month

Customer Charge, Three Phase service $16.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

—	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.053865	$0.048865
Next 54,500 kWh	$0.063865	$0.058865
55,000 kWh and above	$0.068865	$0.063865

Generation Capacity, all kWh $0.000208 per kWh

Fuel and Purchased Power:

—	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.033597	$0.028597
Next 54,500 kWh	$0.043597	$0.038597
55,000 kWh and above	$0.048597	$0.043597

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$2.14 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.19 per month
Customer Delivery	$2.87 per month

Note: Additional meter service charge of $7.00 per month for Three Phase Service.

Energy Charges:

Delivery:

—	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.040800	$0.035800
Next 54,500 kWh	$0.050800	$0.045800
55,000 kWh and above	$0.055800	$0.050800

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003271 per kWh
System Benefits	$0.000439 per kWh
Transmission	$0.007298 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Tucson Electric Power
The Energy People

Pricing Plan GS-10 FROZEN
General Service

Generation Charges:

Generation Capacity $0.000208 per kWh

Fuel and Purchased Power:

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.033597	$0.028597
Next 54,500 kWh	$0.043597	$0.038597
55,000 kWh and above	$0.048597	$0.043597

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

Deleted: tariff

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan GS-11 - FROZEN
Mobile Home Park Electric Service

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

To mobile home parks for service through a master meter to two or more mobile homes, provided each mobile home served through such master meter will be individually metered and billed by the park operator in accordance with applicable Orders of the Arizona Corporation Commission. Electric service to the park's facilities used by its residents may be supplied under this schedule only if such facilities are served through a master meter which serves two or more mobile homes.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service	$ 9.00 per month
Customer Charge, Three Phase service	$16.00 per month
Energy Charges:	
Summer (May – October, all kWh	$0.055431
Winter (November – April), all kWh	$0.048888
Generation Capacity, all kWh	$0.000208
Fuel and Purchased Power, all kWh	$0.044362

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$2.14 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.19 per month
Customer Delivery	$2.85 per month

Note: Additional meter service charge of $7.00 per month for Three Phase Service.

Energy Charges (kWh):

Delivery:	
Summer (May – October), all kWh	$0.049995 per kWh
Winter (November – April), all kWh	$0.039995 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003271 per kWh
System Benefits	$0.000439 per kWh
Transmission	$0.007298 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity	$0.000208 per kWh
Fuel and Purchased Power	$0.044362 per kWh

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan GS-31
Interruptible Agricultural Pumping

AVAILABILITY

Available for interruptible service to agricultural pumping customers throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

Applicable to separately metered interruptible agricultural water pumping service for irrigation purposes of the Customer only.

Not applicable to resale, breakdown, standby, auxiliary, or any other service except agricultural pumping in accordance with the provisions of this rate schedule.

CHARACTER OF SERVICE

Three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges:

Summer (May – October)	$0.027500 per kWh
Winter (November – April)	$0.022500 per kWh
Generation Capacity	$0.000208 per kWh
Fuel and Purchased Power	$0.042091 per kWh

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

DETERMINATION OF HORSEPOWER FOR BILLING

Horsepower connected shall be the manufacturer's nameplate rating of all equipment of Customer connected for service under this schedule, but not less than 60 hp.

MINIMUM BILL

The Customer guarantees that its load shall be sufficient such that a summation of all the above payments shall be not less than $30.00 per hp connected per contract year (which shall be from April 1 to March 31 of the following year) and in no event less than $1,800.00 per contract year. Minimum payments at the rate of $2.50 per hp of motors connected, but not less than $150.00 shall be made monthly.

If during the contract year the total payments exceed the annual guarantee of $30.00 per hp connected but not less than $1,800.00, then the Customer shall be credited the difference between the amount actually paid during the contract year and the amount which would have been paid had the monthly minimum charge not been applied.

TERMS AND CONDITIONS OF SERVICE

1. Customer must furnish, install, own, and maintain at each point of delivery all necessary Company approved equipment which will enable the Company to interrupt service with its master control station.

2. Service may be interrupted by Company during certain periods of the day not exceeding six hours in any 24-hour period.

3. Company will endeavor to give customer one hour notice of impending interruption; however, service may be interrupted without notice should Company deem such action necessary.

4. Where service other than agricultural pumping to which this rate is applicable has been taken hereunder, the general service rate shall be applied on a monthly basis to all usage billed hereunder during the previous twelve months less the aggregate of payments made hereunder for the same period of time. The general service rate shall continue to apply until the unauthorized service is permanently separated from the agricultural pumping service.

5. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy Charges:	
Delivery:	
Summer (May – October)	$0.014435 per kWh
Winter (November – April)	$0.009435 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003271 per kWh
System Benefits	$0.000439 per kWh
Transmission	$0.007298 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Generation Capacity	$0.000208 per kWh
Fuel and Purchased Power	$0.042091 per kWh

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4

Transmission Credit – Rider No. 5.

Pricing Plan GS-76N
General Service Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service	$ 9.00 per month
Customer Charge, Three Phase service	$16.00 per month

Energy Charges:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.090729	$0.054919	$0.041229
Next 54,500 kWh	$0.100729	$0.064919	$0.051229
55,000 kWh and above	$0.105729	$0.069919	$0.056229

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.079700	$0.030200
Next 54,500 kWh	$0.089700	$0.040200
55,000 kWh and above	$0.094700	$0.045200

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak: there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

Generation Capacity, all kWhs $0.000208 per kWh

Fuel and Purchased Power:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.070461	$0.034651	$0.020961
Next 54,500 kWh	$0.080461	$0.044651	$0.030961
55,000 kWh and above	$0.085461	$0.049651	$0.035961

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.059431	$0.009931
Next 54,500 kWh	$0.069431	$0.019931
55,000 kWh and above	$0.074431	$0.024931

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$2.14 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.19 per month
Customer Delivery	$2.87 per month

Note: Additional meter service charge of $7.00 per month for Three Phase Service.

Pricing Plan GS-76N
General Service Time-of-Use

Energy Charges:

Delivery:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.077664	$0.041854	$0.028164
Next 54,500 kWh	$0.087664	$0.051854	$0.038164
55,000 kWh and above	$0.092664	$0.056854	$0.043164

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.066635	$0.017135
Next 54,500 kWh	$0.076635	$0.027135
55,000 kWh and above	$0.081635	$0.032135

Fixed Must-Run (See Must-Run Generation – Rider No. 2) $0.003271 per kWh

System Benefits $0.000439 per kWh

Transmission $0.007298 per kWh

Transmission Ancillary Services

System Control & Dispatch $0.000099 per kWh
Reactive Supply and Voltage Control $0.000390 per kWh
Regulation and Frequency Response $0.000377 per kWh
Spinning Reserve Service $0.001024 per kWh
Supplemental Reserve Service $0.000167 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000208 per kWh

Fuel and Purchased Power:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.070461	$0.034651	$0.020961
Next 54,500 kWh	$0.080461	$0.044651	$0.030961
55,000 kWh and above	$0.085461	$0.049651	$0.035961

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.059431	$0.009931
Next 54,500 kWh	$0.069431	$0.019931
55,000 kWh and above	$0.074431	$0.024931

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

- Must-Run Generation – Rider No. 2;
- Transmission and Ancillary Services – Rider No. 3;
- Termination Costs Regulatory Asset – Rider No. 4;
- Transmission Credit – Rider No. 5.

Pricing Plan GS-85N
General Service Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge $371.88 per month

Demand Charges:
On-peak $3.00 per kW
Off-peak $1.00 per kW

Energy Charges:

	SUMMER (May – October)	WINTER (November – April)
On-peak	$0.056992	$0.052310
Shoulder-peak	$0.035742	N/A
Off-peak	$0.041076	$0.031060

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak: there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

Generation Capacity, all kWhs $0.000208 per kWh

Fuel and Purchased Power:

	SUMMER (May – October)	WINTER (November – April)
On-peak	$0.081447	$0.069950
Shoulder-peak	$0.031947	N/A
Off-peak	$0.045637	$0.020450

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$223.13 per month
Meter Reading	$ 18.59 per month
Billing & Collection	$111.56 per month
Customer Delivery	$ 18.59 per month

Energy Charges:

Delivery:

On-peak	$3.00 per kW
Off-peak	$1.00 per kW

	SUMMER (May – October)	WINTER (November – April)
On-peak	$0.043927	$0.039245
Shoulder-peak	$0.022677	N/A
Off-peak	$0.028011	$0.017995

Fixed Must-Run (See Must-Run Generation – Rider No. 2) $0.003271 per kWh

System Benefits $0.000439 per kWh

Transmission $0.007298 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000208 per kWh

Fuel and Purchased Power:

	SUMMER (May – October)	WINTER (November – April)
On-peak	$0.081447	$0.069950
Shoulder-peak	$0.031947	N/A
Off-peak	$0.045637	$0.020450

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:
Must-Run Generation – Rider No. 2;
Transmission and Ancillary Services – Rider No. 3;
Termination Costs Regulatory Asset – Rider No. 4;
Transmission Credit – Rider No. 5.

Pricing Plan LLP-90N
Large Light and Power Service Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

CHARACTER OF SERVICE
Service shall be three phase, 60 Hertz, Primary Service, and shall be supplied directly from any 46,000 volt, or higher voltage, system at a delivery voltage of not less than 13,800 volts and delivered at a single point of delivery unless otherwise specified in the contract.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge — $500.00 per month

Demand Charges:
- On-peak — $7.00 per kW
- Off-peak — $2.33 per kW

Energy Charges:

	Summer (May – October)	Winter (November - April)
On-Peak	$0.032950	$0.028980
Shoulder-Peak	$0.020450	N/A
Off-Peak	$0.023270	$0.016480

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

_____On-Peak is 2:00 p.m. to 6:00 p.m.

_____Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

_____Off-Peak is 8:00 p.m. to 12:00 p.m.

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

_____On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

_____Shoulder-Peak; there are no shoulder peak periods in the winter.

_____Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

Generation Capacity, all kWhs $0.000414 per kWh

Fuel and Purchased Power:

	Summer (May – October)	Winter (November - April)
On-Peak	$0.048676	$0.037836
Shoulder-Peak	$0.036176	N/A
Off-Peak	$0.038996	$0.044706

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

PRIMARY SERVICE

The above rate is subject to Primary Service and Metering. The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers

POWER FACTOR ADJUSTMENT

The above rate is subject to a discount or a charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is above or below 90% lagging to a maximum discount of 13.0¢ per kW of billing demand per month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$300.00 per month
Meter Reading	$025.00 per month
Billing & Collection	$150.00 per month
Customer Delivery	$025.00 per month

Energy Charges:

Delivery:

On-peak	$7.00 per kW
Off-peak	$2.33 per kW

	Summer (May – October)	Winter (November - April)
On-Peak	$0.020941	$0.016971
Shoulder-Peak	$0.008441	N/A
Off-Peak	$0.011261	$0.004471

Fixed Must-Run (See Must-Run Generation – Rider No. 2) $0.003655 per kWh

System Benefits $0.000428 per kWh

Transmission $0.006184 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000084 per kWh
Reactive Supply and Voltage Control	$0.000330 per kWh
Regulation and Frequency Response	$0.000320 per kWh
Spinning Reserve Service	$0.000867 per kWh
Supplemental Reserve Service	$0.000141 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000414 per kWh

Fuel and Purchased Power:

	Summer (May – October)	Winter (November - April)
On-Peak	$0.048676	$0.037836
Shoulder-Peak	$0.036176	N/A
Off-Peak	$0.038996	$0.044706

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;
Transmission and Ancillary Services – Rider No. 3;
Termination Costs Regulatory Asset – Rider No. 4;
Transmission Credit – Rider No. 5.

Pricing Plan PS-40
Municipal Service

AVAILABILITY

Available for Municipal Service where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

Applicable for service to the City of Tucson and City of South Tucson for Municipal buildings and grounds.

Not applicable to resale, breakdown, standby, or auxiliary service or to buildings used for residential purposes.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, at secondary voltage and subject to availability at point of delivery approved by the Company.

RATE

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges:	
Summer (May – October), all kWh	$0.059931
Winter (November – April), all kWh	$0.049931
Generation Capacity, all kWhs	$0.000328
Fuel and Purchased Power:	
Summer (May – October, all kWh	$0.063934
Winter (November – April), all kWh	$0.034866

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy Charges:	
Delivery:	
Summer (May – October, all kWh	$0.048337
Winter (November – April), all kWh	$0.038337
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003308 per kWh

System Benefits	$0.000434 per kWh
Transmission	$0.006129 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000083 per kWh
Reactive Supply and Voltage Control	$0.000327 per kWh
Regulation and Frequency Response	$0.000317 per kWh
Spinning Reserve Service	$0.000860 per kWh
Supplemental Reserve Service	$0.000140 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Generation Capacity	$0.000328 per kWh
Fuel and Purchased Power:	
Summer (May – October), all kWh	$0.063934
Winter (November – April), all kWh	$0.034866

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Tucson Electric Power
The Energy People

Pricing Plan PS-43
Municipal Water Pumping Service

AVAILABILITY
Available for service to the City of Tucson Water Utility and private water Companies where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Applicable for service to booster stations and wells used for domestic water supply.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as elected by Customer and subject to availability at point of delivery approved by the Company. Primary metering may be used by mutual agreement.

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges Firm Service:	
Summer (May – October), all kWh	$0.059931
Winter (November – April), all kWh	$0.049931
Energy Charges Interruptible Service:	
Summer (May – October), all kWh	$0.029931
Winter (November – April), all kWh	$0.028931
Generation Capacity, all kWh	$0.000328
Fuel and Purchased Power Firm Service:	
Summer (May – October), all kWh	$0.049500
Winter (November – April), all kWh	$0.039500
Fuel and Purchased Power Interruptible Service:	
Summer (May – October), all kWh	$0.019500
Winter (November – April), all kWh	$0.019500

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

Pricing Plan PS-43
Municipal Water Pumping Service

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy Charges:

Delivery Firm Service:

Summer (May – October), all kWh	$0.048337
Winter (November – April), all kWh	$0.038337

Delivery Interruptible Service:

Summer (May – October), all kWh	$0.018337
Winter (November – April), all kWh	$0.017337

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003308 per kWh
System Benefits	$0.000434 per kWh
Transmission	$0.006129 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000083 per kWh
Reactive Supply and Voltage Control	$0.000327 per kWh
Regulation and Frequency Response	$0.000317 per kWh
Spinning Reserve Service	$0.000860 per kWh
Supplemental Reserve Service	$0.000140 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity	$0.000328 per kWh

Fuel and Purchased Power Firm Service:

Summer (May – October), all kWh	$0.049500
Winter (November – April), all kWh	$0.039500

Fuel and Purchased Power Interruptible Service:

Summer (May – October), all kWh	$0.019500
Winter (November – April), all kWh	$0.019500

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

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FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TERMS AND CONDITIONS OF INTERRUPTIBLE SERVICE

1. Customer must furnish, install, own, and maintain at each point of delivery all necessary Company approved equipment which will enable the Company to interrupt service with its master control station.

2. Service may be interrupted by Company during certain periods of the day not exceeding six hours in any 24-hour period.

3. Company will endeavor to give Customer one hour notice of impending interruption; however, service may be interrupted without notice should Company deem such action necessary.

4. The interruptible load shall be separately served and metered and shall at no time be connected to facilities serving Customer's firm load. Conversely, the firm load shall be separately served and metered and shall at no time be connected to facilities serving Customer's interruptible load.

5. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

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TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

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The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan PS-41
Traffic Signal and Street Lighting Service

AVAILABILITY
Available for service to the State, a county, city, town, political subdivision, improvement district, or a responsible person or persons for unincorporated communities for Traffic Signal and Street Lighting purposes where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Applicable to Customer owned and maintained traffic signals and public street and highway lighting.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery approved by the Company.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

All kWh @ $0.049353 per kWh

Generation Capacity	$0.000168 per kWh
Fuel and Purchased Power:	$0.037991

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Delivery	$0.012455 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.002218 per kWh
System Benefits	$0.000408 per kWh
Transmission	$0.026736 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000363 per kWh
Reactive Supply and Voltage Control	$0.001427 per kWh
Regulation and Frequency Response	$0.001383 per kWh
Spinning Reserve Service	$0.003750 per kWh
Supplemental Reserve Service	$0.000612 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity	$0.000168 per kWh
Fuel and Purchased Power:	$0.037991

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan PS-50
Public Street Lighting Service

AVAILABILITY
Available for service for lighting public streets, alleys, thoroughfares, public parks, and playgrounds by use of Company's standard facilities where such service is contracted under this pricing plan by the state, a county, city, town, political subdivision, improvement district, or a responsible person or persons for unincorporated communities.

APPLICABILITY
Applicable to street lighting service from dusk to dawn and Company will own, operate, and maintain the street light system including lamps and globe replacements.

CHARACTER OF SERVICE
Multiple or series street lighting system at option of Company and at one standard nominal voltage.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
per unit per month	$10.33	$10.33	$10.33	$15.51	$23.92	$19.57	$3.61

Note:

The watt high pressure sodium lamps are charged per unit per month.

Per one pole addition and an extension of up to 100 feet of overhead service are charged per pole.

Underground Service is per 100 watt or less high pressure sodium lamp unit per month mounted on standard pole.

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Generation Capacity	$0.0028	$0.0035	$0.0050	$0.0126	$0.0202
Fuel & Purchased Power	$0.6280	$0.7993	$1.1420	$2.8540	$4.5670

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

STANDARD LAMP UNITS, OVERHEAD SERVICE

(1) The standard 100 watt lamp unit for overhead service is a 9,500 lumen high pressure sodium unit, mounted on a four foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 25 feet above ground level.

(2) The standard 250 watt lamp unit for overhead service is a 27,500 lumen high pressure sodium unit, mounted on an eight foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 27 feet above ground level.

(3) The standard 400 watt lamp unit for overhead service is a 50,000 lumen high pressure sodium unit, mounted on an eighteen foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 35 feet above ground level.

(4) The standard 100 watt lamp unit for underground service is a 9,500 lumen high pressure sodium post top unit mounted on a pole approximately 15 feet above ground level.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Delivery	$9.72	$9.56	$9.22	$12.75	$19.48
Fixed Must-Run	$0.04	$0.05	$0.07	$0.17	$0.27
System Benefits	$0.01	$0.01	$0.01	$0.03	$0.05
Transmission	$0.44	$0.56	$0.80	$2.01	$3.21
Transmission Ancillary					
System Control & Load Dispatch	$0.01	$0.01	$0.01	$0.03	$0.04
Reactive Supply and Voltage Control	$0.02	$0.03	$0.04	$0.11	$0.17
Regulation and Frequency Response	$0.02	$0.03	$0.04	$0.10	$0.17
Spinning Reserve Service	$0.06	$0.08	$0.11	$0.28	$0.45
Supplemental Reserve Service	$0.01	$0.01	$0.02	$0.05	$0.07
Energy Imbalance Service: currently charged pursuant to the Company's OATT.					
Generation Capacity:	$0.01	$.01	$0.01	$0.01	$0.02
Fuel and Purchased Power	$0.63	$0.80	$1.14	$2.85	$4.57

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

SPECIAL PROVISIONS

(1) Installation of a light on an existing pole is subject to prior approval of Company.

(2) For underground service, where customer provides trenching up to 10 feet in accordance with Company's electric service requirements, customer shall be billed at the rates for overhead service.

(3) Extensions beyond 100 feet and all installations other than those addressed in this pricing plan will require specific agreements providing adequate revenue or arrangements for construction financing.

(4) The Customer is not authorized to make connections to this lighting circuit or to make attachments or alterations to the Company owned pole.

(5) If a Customer requests a relocation of a lighting installation, the costs of such relocation must be borne by the Customer.

(6) The Customer is expected to notify the Company when lamp outages occur.

(7) The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

(8) After the minimum contract period, if any, has expired, this agreement shall be extended from year to year unless written notice of desire to terminate is given by either party at least thirty (30) days prior to the end of any such annual extension date.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan GS-51
Private Street and Area Lighting Service

AVAILABILITY
At any point where the Company in its judgment has facilities of adequate capacity and suitable voltage available.

APPLICABILITY
To any Customer for private street or outdoor area lighting where this service can be supplied from existing facilities of the Company.

Service is from dusk to dawn and the Company will install, own, operate, and maintain the complete lighting installation including lamp replacements.

Not applicable to resale service.

CHARACTER OF SERVICE
Multiple or series street lighting system at option of Company and at one standard nominal voltage.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
per unit per month	$10.33	$10.33	$10.33	$15.51	$23.92	$19.57	$3.61

Note:

The watt high pressure sodium lamps are charged per unit per month.

Per one pole addition and an extension of up to 100 feet of overhead service are charged per pole.

Underground Service is per 100 watt or less high pressure sodium lamp unit per month mounted on standard pole.

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Generation Capacity	$0.0028	$0.0035	$0.0050	$0.0126	$0.0202
Fuel & Purchased Power	$0.6280	$0.7993	$1.1420	$2.8540	$4.5670

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

STANDARD LAMP UNITS, OVERHEAD SERVICE

(1) The standard 100 watt lamp unit for overhead service is a 9,500 lumen high pressure sodium unit, mounted on a four foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 25 feet above ground level.

(2) The standard 250 watt lamp unit for overhead service is a 27,500 lumen high pressure sodium unit, mounted on an eight foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 27 feet above ground level.

(3) The standard 400 watt lamp unit for overhead service is a 50,000 lumen high pressure sodium unit, mounted on an eighteen foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 35 feet above ground level.

(4) The standard 100 watt lamp unit for underground service is a 9,500 lumen high pressure sodium post top unit mounted on a pole approximately 15 feet above ground level.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Delivery	$9.72	$9.56	$9.22	$12.75	$19.48
Fixed Must-Run	$0.04	$0.05	$0.07	$0.17	$0.27
System Benefits	$0.01	$0.01	$0.01	$0.03	$0.05
Transmission	$0.44	$0.56	$0.80	$2.01	$3.21
Transmission Ancillary					
System Control & Load Dispatch	$0.01	$0.01	$0.01	$0.03	$0.04
Reactive Supply and Voltage Control	$0.02	$0.03	$0.04	$0.11	$0.17
Regulation and Frequency Response	$0.02	$0.03	$0.04	$0.10	$0.17
Spinning Reserve Service	$0.06	$0.08	$0.11	$0.28	$0.45
Supplemental Reserve Service	$0.01	$0.01	$0.02	$0.05	$0.07
Energy Imbalance Service: currently charged pursuant to the Company's OATT.					
Generation Capacity:	$0.01	$.01	$0.01	$0.01	$0.02
Fuel and Purchased Power	$0.63	$0.80	$1.14	$2.85	$4.57

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

SPECIAL PROVISIONS

(1) Installation of a light on an existing pole is subject to prior approval of Company.

(2) For underground service, where customer provides trenching up to 10 feet in accordance with Company's electric service requirements, customer shall be billed at the rates for overhead service.

(3) Extensions beyond 100 feet and all installations other than those addressed in this pricing plan will require specific agreements providing adequate revenue or arrangements for construction financing.

(4) The Customer is not authorized to make connections to this lighting circuit or to make attachments or alterations to the Company owned pole.

(5) If a Customer requests a relocation of a lighting installation, the costs of such relocation must be borne by the Customer.

(6) The Customer is expected to notify the Company when lamp outages occur.

(7) The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

(8) After the minimum contract period, if any, has expired, this agreement shall be extended from year to year unless written notice of desire to terminate is given by either party at least thirty (30) days prior to the end of any such annual extension date.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

REDLINED VERSION

Pricing Plan R-01 FROZEN
Residential Electric Service

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single phase or three phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter; however, electric water heating may be metered separately.

Not applicable to resale, breakdown, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, nominal 120/240 volts.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service $ 9.00 per month

Customer Charge, Three Phase service $15.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.045818	$0.040818
Next 3,000 kWh	$0.055818	$0.050818
3,501 kWh and above	$0.060818	$0.055818

Generation Capacity, all kWh $0.000335 per kWh

Fuel and Purchased Power:

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.037621	$0.032621
Next 3,000 kWh	$0.047621	$0.042621
3,501 kWh and above	$0.052621	$0.047621

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.55 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.25 per month
Customer Delivery	$3.40 per month

Note: Additional meter service charge of $6.00 per month for Three Phase Service.

Energy (kWh) and Demand Charges (kW):

Delivery

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.031888	$0.026888
Next 3,000 kWh	$0.041888	$0.036888
3,501 kWh and above	$0.046888	$0.041888

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003822 per kWh
System Benefits	$0.000463 per kWh
Transmission	$0.007525 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000335 per kWh

Fuel and Purchased Power

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.037621	$0.032621
Next 3,000 kWh	$0.047621	$0.042621
3,501 kWh and above	$0.052621	$0.047621

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan R-02 FROZEN
Residential Electric Water Heating Service

AVAILABILITY
This rate is limited to installations and customers served under Pricing Plan No. 2 on the effective date of this pricing plan sheet.

APPLICABILITY
To separately metered single phase residential off-peak water heating service where general residential service is also provided under Pricing Plan No. 1. When service under Pricing Plan No. 2 is discontinued, the Company will either combine usage and bill under Pricing Plan No. 1 or modify the service entrance equipment so all service is supplied through the Pricing Plan No. 1 meter.

Not applicable to three phase service, resale, breakdown, standby, auxiliary, or any other service except off-peak water heating in accordance with the provisions of this pricing plan.

Where service other than water heating to which this rate is applicable has been taken hereunder, the regular rate for such service shall be applied on a monthly basis to all consumption billed hereunder during the previous twelve months, less the aggregate of payments made hereunder for the same period of time. The regular rate shall continue to apply until the unauthorized service is permanently separated from the off-peak water heating service.

CHARACTER OF SERVICE
Single phase, 60 Hertz, nominal 120/240 volts.

Service may be controlled by the Company by disconnecting electricity during certain periods of the day not exceeding 8 hours in any 24-hour period, as determined by the Company from time to time.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges:

Delivery, all kWh	$0.050000 per kWh
Generation Capacity, all kWh	$0.000335 per kWh
Fuel and Purchased Power, all kWh	$0.044362 per kWh

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

Pricing Plan R-02 FROZEN
Residential Electric Water Heating Service

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy:

Delivery	$0.036070 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003822 per kWh
System Benefits	$0.000463 per kWh
Transmission	$0.007525 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Generation Capacity	$0.000335 per kWh
Fuel and Purchased Power	$0.044362 per kWh

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

The electric water heating equipment and installation shall conform to the Company's requirements and be for normal domestic use. The heater shall be of the storage type and not less than 30-gallon capacity. For a water heater equipped with one heating element, the rating of the heating element shall not exceed 6,000 watts. For a water heater equipped with more than one heating element, the rating of any such heating element shall not exceed 6,000 watts, and, if the total of the ratings of the elements exceeds 6,000 watts, they shall be thermostatically interlocked so that they cannot operate simultaneously and thereby exceed 6,000 watts. The Customer shall provide the necessary wiring to permit the installation of the Company's metering and control equipment.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan R-70N
Residential Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Service is available to individual private dwellings and individually metered multi-family units when all service is supplied at one point of delivery and energy is metered through one meter; however, controlled off-peak electric water heating may be metered separately.

Not applicable to three phase service, resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

Service under this pricing plan will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
Single phase, 60 Hertz, nominal 120/240 volts.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge: $9.00 per month

Energy Charges:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.081084	$0.046780	$0.031584
Next 3,000 kWh	$0.091084	$0.056780	$0.041584
3,501 kWh and above	$0.096084	$0.061780	$0.046584

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.068745	$0.019245
Next 3,000 kWh	$0.078745	$0.029245
3,501 kWh and above	$0.083745	$0.034245

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak: there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

If a Summer or Winter holiday falls on Saturday, the preceding Friday is designated off-peak; if a holiday falls on Sunday, the following Monday is designated off-peak.

Energy Charges continued:

Generation Capacity $0.000335 per kWh

Fuel and Purchased Power:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.072887	$0.038583	$0.023387
Next 3,000 kWh	$0.082887	$0.048583	$0.033387
3,501 kWh and above	$0.087887	$0.053583	$0.038387

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.060548	$0.011048
Next 3,000 kWh	$0.070548	$0.021048
3,501 kWh and above	$0.075548	$0.026048

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.55 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.25 per month
Customer Delivery	$3.40 per month

Note: Additional meter service charge of $6.00 per month for Three Phase Service.

Pricing Plan R-70N
Residential Time-of-Use

Energy:

Delivery

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.067154	$0.032850	$0.017654
Next 3,000 kWh	$0.077154	$0.042850	$0.027654
3,501 kWh and above	$0.082154	$0.047850	$0.032654

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.054815	$0.005315
Next 3,000 kWh	$0.064815	$0.015315
3,501 kWhs and above	$0.069815	$0.020315

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003822 per kWh
System Benefits	$0.000463 per kWh
Transmission	$0.007525 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000102 per kWh
Reactive Supply and Voltage Control	$0.000402 per kWh
Regulation and Frequency Response	$0.000389 per kWh
Spinning Reserve Service	$0.001055 per kWh
Supplemental Reserve Service	$0.000172 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000335 per kWh

Fuel and Purchased Power:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.072887	$0.038583	$0.023387
Next 3,000 kWh	$0.082887	$0.048583	$0.033387
3,501 kWh and above	$0.087887	$0.053583	$0.038387

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.060548	$0.011048
Next 3,000 kWh	$0.070548	$0.021048
3,501 kWh and above	$0.075548	$0.026048

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Rider 5
Transmission Cost Adjustment Charge ("TCAC")

The Transmission Cost Adjustment Charge ("TCAC") shall apply to all of the Company's retail pricing plans. All provisions of the applicable pricing plan will apply in addition to the TCAC authorized by this Rider.

Pricing plans to which the TCAC applies include transmission and ancillary service components listed in the table below. The listed transmission and ancillary service components are based on the Company's Federal Energy Regulatory Commission ("FERC") - approved Open Access Transmission Tariff ("OATT"). The listed transmission and ancillary service components are calculated on a volumetric basis by class of service.

Pursuant to this Rider, the TCAC, which is an annual adjustment to the transmission and ancillary service components, will be submitted to the Commission for review. In the event that the Company's FERC-approved OATT changes, TEP will file an additional recalculated TCAC, unless the regular annual adjustment addresses the OATT change. The TCAC is based upon the prior year's annual Transmission and Ancillary Service costs and retail energy sales. Transmission and Ancillary Service costs are calculated by applying the Company's approved OATT rates to TEP's retail jurisdictional sales. This TCAC will be applied volumetrically to kilowatt-hour sales under applicable electric pricing plans. The TCAC applies to all system sales and will not vary by class of service.

The initial transmission and ancillary service components of retail rates and are as follows:

	Residential	General Service	Lg Light & Power	Lighting	Public Authority
Transmission	$0.006950	$0.006740	$0.005711	$0.024692	$0.005660
Ancillary Services					
System Control - Load Dispatch	$0.000094	$0.000092	$0.000078	$0.000336	$0.000077
Reactive Supply and Voltage Control	$0.000371	$0.000360	$0.000305	$0.001318	$0.000302
Regulation and Frequency Response	$0.000359	$0.000349	$0.000295	$0.001277	$0.000293
Spinning Reserve Service	$0.000975	$0.000945	$0.000801	$0.003463	$0.000794
Supplemental Reserve Service	$0.000159	$0.000154	$0.000131	$0.000565	$0.000130

Note: All values presented as $/kWh

Pricing Plans:
R-201A FROZEN,
R-201BN AND R-201CN
Special Residential Electric Service

AVAILABILITY
Throughout the entire area where facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To single phase electric service in individual residences as described in current program details when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this Schedule requires that the customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below and that the customer's home conform to the standards of the Heating, Cooling and Comfort Guarantee program as in effect at the time of subscription to this Schedule. Notwithstanding the above, the customer's use of solar energy for any purpose shall not preclude subscription to this Schedule. Two different Options are available under this Schedule: BN, & CN. Subscription eligibility requirements are as follows:

Option A: This option is FROZEN to new customers.
Option BN: Customer must meet above conditions and must purchase under the time-of-use structure.
Option CN: Customer must meet above conditions and must use either (i.) solar equipment for water heating requirements during the year or (ii.) an electric heat pump water heater, or both (i.) and (ii.), and must purchase under the time-of-use structure applicable to Option CN.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
Single phase, 60 Hertz, nominal 120/240 volts.

PRICE UNDER OPTION A
A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Minimum Customer Charge $ 9.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.053500	$0.048500	$0.046000
Next 3,000 kWh	$0.063500	$0.058500	$0.056000
3,501 kWh and above	$0.068500	$0.063500	$0.061000

Generation Capacity, all kWh $0.000335 per kWh

Fuel and Purchase Power:

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.025640	$0.020640	$0.018140
Next 3,000 kWh	$0.035640	$0.030640	$0.028140
3,501 kWh and above	$0.040640	$0.035640	$0.033140

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

PRICE UNDER OPTION BN

A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Minimum Customer Charge $ 9.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.054100	$0.044100	$0.039100
Next 3,000 kWh	$0.064100	$0.054100	$0.049100
3,501 kWh and above	$0.059100	$0.049100	$0.044100

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.049100	$0.039100	$0.034100
Next 3,000 kWh	$0.059100	$0.049100	$0.044100
3,501 kWh and above	$0.054100	$0.044100	$0.039100

The Mid-Summer and Remaining Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day:

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.
Off-Peak is 8:00 p.m. to 12:00 p.m.
On-Peak is 2:00 p.m. to 6:00 p.m.

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.046600	$0.041600
Next 3,000 kWh	$0.056600	$0.051600
3,501 kWh and above	$0.051600	$0.046600

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day:

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: there are no shoulder peak periods in the winter.
Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

If a Summer or Winter holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

Energy Charges continued:

Generation Capacity $0.000335 per kWh

Fuel and Purchased Power:

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.031240	$0.021240	$0.016240
Next 3,000 kWh	$0.041240	$0.031240	$0.026240
3,501 kWh and above	$0.036240	$0.026240	$0.021240

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.026240	$0.016240	$0.011240
Next 3,000 kWh	$0.036240	$0.026240	$0.021240
3,501 kWh and above	$0.031240	$0.021240	$0.016240

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.023740	$0.018740
Next 3,000 kWh	$0.033740	$0.028740
3,501 kWh and above	$0.028740	$0.023740

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchase Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

PRICE UNDER OPTION CN

A monthly net bill at the following rates plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Minimum Customer Charge $ 9.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.053018	$0.043218	$0.038318
Next 3,000 kWh	$0.062818	$0.053018	$0.048118
3,501 kWh and above	$0.057918	$0.048118	$0.043218

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.048118	$0.038318	$0.033418
Next 3,000 kWh	$0.057918	$0.048118	$0.043218
3,501 kWh and above	$0.053018	$0.043218	$0.038318

The Mid-Summer and Remaining Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day:

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.
Off-Peak is 8:00 p.m. to 12:00 p.m.
On-Peak is 2:00 p.m. to 6:00 p.m.

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.045668	$0.040768
Next 3,000 kWh	$0.055468	$0.050568
3,501 kWh and above	$0.0450568	$0.045668

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day:

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak – there are no shoulder peak periods in the winter.
Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

If a Summer or Winter holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

Energy Charges continued:

Generation Capacity $0.000335 per kWh

Fuel and Purchase Power:

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.029823	$0.020023	$0.015123
Next 3,000 kWh	$0.039623	$0.029823	$0.024923
3,501 kWh and above	$0.034723	$0.024923	$0.020023

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.024923	$0.015123	$0.010223
Next 3,000 kWh	$0.034723	$0.024923	$0.020023
3,501 kWh and above	$0.029823	$0.020023	$0.015123

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.022473	$0.017573
Next 3,000 kWh	$0.032273	$0.027373
3,501 kWh and above	$0.027373	$0.022473

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchase Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE R-201A FROZEN, R-201BN AND R201CN CONSIST OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$1.55 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.25 per month
Customer Delivery	$3.40 per month

Note: Additional meter service charge of $6.00 per month for Three Phase Service.

Energy:

Delivery **(FOR OPTION A ONLY):**

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.039570	$0.0345700038	$0.032070
Next 3,000 kWh	$0.049570	$0.044570	$0.042070
3,501 kWh and above	$0.054570	$0.049570	$0.047070

Delivery **(FOR OPTION BN ONLY):**

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.040170	$0.030170	$0.025170
Next 3,000 kWh	$0.050170	$0.040170	$0.035170
3,501 kWh and above	$0.045170	$0.035170	$0.030170

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.035170	$0.025170	$0.020170
Next 3,000 kWh	$0.045170	$0.035170	$0.030170
3,501 kWh and above	$0.040170	$0.030170	$0.025170

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.032670	$0.027670
Next 3,000 kWh	$0.042670	$0.037670
3,501 kWh and above	$0.037670	$0.032670

Delivery **(FOR OPTION CN ONLY):**

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.039088	$0.029288	$0.024388
Next 3,000 kWh	$0.048888	$0.039088	$0.034188
3,501 kWh and above	$0.043988	$0.034188	$0.029288

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.034188	$0.024388	$0.019488
Next 3,000 kWh	$0.043988	$0.034188	$0.029288
3,501 kWh and above	$0.039088	$0.029288	$0.024388

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.031738	$0.026838
Next 3,000 kWh	$0.041538	$0.036638
3,501 kWh and above	$0.036638	$0.031738

Fixed Must-Run (See Must-Run Generation – Rider No. 2) $0.003822 per kWh

System Benefits $0.000463 per kWh

Transmission $0.007525 per kWh

Transmission Ancillary Services

System Control & Dispatch $0.000102 per kWh
Reactive Supply and Voltage Control $0.000402 per kWh
Regulation and Frequency Response $0.000389 per kWh
Spinning Reserve Service $0.001055 per kWh
Supplemental Reserve Service $0.000172 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000335 per kWh

Fuel and Purchased Power:

(FOR OPTION A ONLY):

	Mid-Summer (June – August)	Remaining Summer (May, September – October)	Winter (November - April)
First 500 kWh	$0.025640	$0.018140	$0.020640
Next 3,000 kWh	$0.035640	$0.028140	$0.030640
3,501 kWh and above	$0.040640	$0.033140	$0.035640

(FOR OPTION BN ONLY):

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.031240	$0.021240	$0.016240
Next 3,000 kWh	$0.041240	$0.031240	$0.026240
3,501 kWh and above	$0.036240	$0.026240	$0.021240

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.026240	$0.016240	$0.011240
Next 3,000 kWh	$0.036240	$0.026240	$0.021240
3,501 kWh and above	$0.031240	$0.021240	$0.016240

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.023740	$0.018740
Next 3,000 kWh	$0.033740	$0.028740
3,501 kWh and above	$0.028740	$0.023740

(FOR OPTION CN ONLY):

MID-SUMMER (JUNE – AUGUST)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.039088	$0.029288	$0.024388
Next 3,000 kWh	$0.048888	$0.039088	$0.034188
3,501 kWh and above	$0.043988	$0.034188	$0.029288

REMAINING SUMMER (MAY, SEPTEMBER - OCTOBER)			
	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.034188	$0.024388	$0.019488
Next 3,000 kWh	$0.043988	$0.034188	$0.029288
3,501 kWh and above	$0.039088	$0.029288	$0.024388

WINTER (NOVEMBER – APRIL)		
	On-Peak	Off-Peak
First 500 kWh	$0.031738	$0.026838
Next 3,000 kWh	$0.041538	$0.036638
3,501 kWh and above	$0.036638	$0.031738

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan GS-10 FROZEN
General Service

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service $ 9.00 per month

Customer Charge, Three Phase service $16.00 per month

Energy Charges: All energy charges below are charged on a per kWh basis.

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.053865	$0.048865
Next 54,500 kWh	$0.063865	$0.058865
55,000 kWh and above	$0.068865	$0.063865

Generation Capacity, all kWh $0.000208 per kWh

Fuel and Purchased Power:

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.033597	$0.028597
Next 54,500 kWh	$0.043597	$0.038597
55,000 kWh and above	$0.048597	$0.043597

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$2.14 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.19 per month
Customer Delivery	$2.87 per month

Note: Additional meter service charge of $7.00 per month for Three Phase Service.

Energy Charges:

Delivery:

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.040800	$0.035800
Next 54,500 kWh	$0.050800	$0.045800
55,000 kWh and above	$0.055800	$0.050800

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003271 per kWh
System Benefits	$0.000439 per kWh
Transmission	$0.007298 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000208 per kWh

Fuel and Purchased Power:

	Summer (May – October)	Winter (November - April)
First 500 kWh	$0.033597	$0.028597
Next 54,500 kWh	$0.043597	$0.038597
55,000 kWh and above	$0.048597	$0.043597

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan GS-11 - FROZEN
Mobile Home Park Electric Service

AVAILABILITY

Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

To mobile home parks for service through a master meter to two or more mobile homes, provided each mobile home served through such master meter will be individually metered and billed by the park operator in accordance with applicable Orders of the Arizona Corporation Commission. Electric service to the park's facilities used by its residents may be supplied under this schedule only if such facilities are served through a master meter which serves two or more mobile homes.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service	$ 9.00 per month
Customer Charge, Three Phase service	$16.00 per month
Energy Charges:	
Summer (May – October, all kWh	$0.055431
Winter (November – April), all kWh	$0.048888
Generation Capacity, all kWh	$0.000208
Fuel and Purchased Power, all kWh	$0.044362

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$2.14 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.19 per month
Customer Delivery	$2.85 per month

Note: Additional meter service charge of $7.00 per month for Three Phase Service.

Energy Charges (kWh):

Delivery:	
Summer (May – October), all kWh	$0.049995 per kWh
Winter (November – April), all kWh	$0.039995 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003271 per kWh
System Benefits	$0.000439 per kWh
Transmission	$0.007298 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity	$0.000208 per kWh
Fuel and Purchased Power	$0.044362 per kWh

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan GS-31
Interruptible Agricultural Pumping

AVAILABILITY

Available for interruptible service to agricultural pumping customers throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

Applicable to separately metered interruptible agricultural water pumping service for irrigation purposes of the Customer only.

Not applicable to resale, breakdown, standby, auxiliary, or any other service except agricultural pumping in accordance with the provisions of this rate schedule.

CHARACTER OF SERVICE

Three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges:

Summer (May – October)	$0.027500 per kWh
Winter (November – April)	$0.022500 per kWh
Generation Capacity	$0.000208 per kWh
Fuel and Purchased Power	$0.042091 per kWh

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

DETERMINATION OF HORSEPOWER FOR BILLING

Horsepower connected shall be the manufacturer's nameplate rating of all equipment of Customer connected for service under this schedule, but not less than 60 hp.

MINIMUM BILL

The Customer guarantees that its load shall be sufficient such that a summation of all the above payments shall be not less than $30.00 per hp connected per contract year (which shall be from April 1 to March 31 of the following year) and in no event less than $1,800.00 per contract year. Minimum payments at the rate of $2.50 per hp of motors connected, but not less than $150.00 shall be made monthly.

If during the contract year the total payments exceed the annual guarantee of $30.00 per hp connected but not less than $1,800.00, then the Customer shall be credited the difference between the amount actually paid during the contract year and the amount which would have been paid had the monthly minimum charge not been applied.

TERMS AND CONDITIONS OF SERVICE

1. Customer must furnish, install, own, and maintain at each point of delivery all necessary Company approved equipment which will enable the Company to interrupt service with its master control station.

2. Service may be interrupted by Company during certain periods of the day not exceeding six hours in any 24-hour period.

3. Company will endeavor to give customer one hour notice of impending interruption; however, service may be interrupted without notice should Company deem such action necessary.

4. Where service other than agricultural pumping to which this rate is applicable has been taken hereunder, the general service rate shall be applied on a monthly basis to all usage billed hereunder during the previous twelve months less the aggregate of payments made hereunder for the same period of time. The general service rate shall continue to apply until the unauthorized service is permanently separated from the agricultural pumping service.

5. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy Charges:	
Delivery:	
Summer (May – October)	$0.014435 per kWh
Winter (November – April)	$0.009435 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003271 per kWh
System Benefits	$0.000439 per kWh
Transmission	$0.007298 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Generation Capacity	$0.000208 per kWh
Fuel and Purchased Power	$0.042091 per kWh

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4

Transmission Credit – Rider No. 5.

Pricing Plan GS-76N
General Service Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge, Single Phase service	$ 9.00 per month
Customer Charge, Three Phase service	$16.00 per month

Energy Charges:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.090729	$0.054919	$0.041229
Next 54,500 kWh	$0.100729	$0.064919	$0.051229
55,000 kWh and above	$0.105729	$0.069919	$0.056229

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.079700	$0.030200
Next 54,500 kWh	$0.089700	$0.040200
55,000 kWh and above	$0.094700	$0.045200

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak: there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

Generation Capacity, all kWhs $0.000208 per kWh

Fuel and Purchased Power:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.070461	$0.034651	$0.020961
Next 54,500 kWh	$0.080461	$0.044651	$0.030961
55,000 kWh and above	$0.085461	$0.049651	$0.035961

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.059431	$0.009931
Next 54,500 kWh	$0.069431	$0.019931
55,000 kWh and above	$0.074431	$0.024931

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$2.14 per month
Meter Reading	$0.80 per month
Billing & Collection	$3.19 per month
Customer Delivery	$2.87 per month

Note: Additional meter service charge of $7.00 per month for Three Phase Service.

Energy Charges:

Delivery:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.077664	$0.041854	$0.028164
Next 54,500 kWh	$0.087664	$0.051854	$0.038164
55,000 kWh and above	$0.092664	$0.056854	$0.043164

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.066635	$0.017135
Next 54,500 kWh	$0.076635	$0.027135
55,000 kWh and above	$0.081635	$0.032135

Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003271 per kWh
System Benefits	$0.000439 per kWh
Transmission	$0.007298 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity	$0.000208 per kWh

Fuel and Purchased Power:

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.070461	$0.034651	$0.020961
Next 54,500 kWh	$0.080461	$0.044651	$0.030961
55,000 kWh and above	$0.085461	$0.049651	$0.035961

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.059431	$0.009931
Next 54,500 kWh	$0.069431	$0.019931
55,000 kWh and above	$0.074431	$0.024931

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this tariff:

Must-Run Generation – Rider No. 2;
Transmission and Ancillary Services – Rider No. 3;
Termination Costs Regulatory Asset – Rider No. 4;
Transmission Credit – Rider No. 5.

Pricing Plan GS-85N
General Service Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific rate schedules, when all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge $371.88 per month

Demand Charges:
On-peak $3.00 per kW
Off-peak $1.00 per kW

Energy Charges:

	SUMMER (May – October)	WINTER (November – April)
On-peak	$0.056992	$0.052310
Shoulder-peak	$0.035742	N/A
Off-peak	$0.041076	$0.031060

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak: there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

Generation Capacity, all kWhs $0.000208 per kWh

Fuel and Purchased Power:

	SUMMER (May – October)	WINTER (November – April)
On-peak	$0.081447	$0.069950
Shoulder-peak	$0.031947	N/A
Off-peak	$0.045637	$0.020450

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING

The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers and the above schedule shall be subject to a discount of 20.6¢ per kW per month of the billing demand each month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$223.13 per month
Meter Reading	$ 18.59 per month
Billing & Collection	$111.56 per month
Customer Delivery	$ 18.59 per month

Energy Charges:

Delivery:

On-peak	$3.00 per kW
Off-peak	$1.00 per kW

	SUMMER (May – October)	WINTER (November – April)
On-peak	$0.043927	$0.039245
Shoulder-peak	$0.022677	N/A
Off-peak	$0.028011	$0.017995

Fixed Must-Run (See Must-Run Generation – Rider No. 2) $0.003271 per kWh

System Benefits $0.000439 per kWh

Transmission $0.007298 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000099 per kWh
Reactive Supply and Voltage Control	$0.000390 per kWh
Regulation and Frequency Response	$0.000377 per kWh
Spinning Reserve Service	$0.001024 per kWh
Supplemental Reserve Service	$0.000167 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000208 per kWh

Fuel and Purchased Power:

	SUMMER (May – October)	WINTER (November – April)
On-peak	$0.081447	$0.069950
Shoulder-peak	$0.031947	N/A
Off-peak	$0.045637	$0.020450

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;
Transmission and Ancillary Services – Rider No. 3;
Termination Costs Regulatory Asset – Rider No. 4;
Transmission Credit – Rider No. 5.

Pricing Plan LLP-90N
Large Light and Power Service Time-of-Use

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

CHARACTER OF SERVICE
Service shall be three phase, 60 Hertz, Primary Service, and shall be supplied directly from any 46,000 volt, or higher voltage, system at a delivery voltage of not less than 13,800 volts and delivered at a single point of delivery unless otherwise specified in the contract.

PRICE SCHEDULE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Customer Charge $500.00 per month

Demand Charges:
On-peak $7.00 per kW
Off-peak $2.33 per kW

Energy Charges:

	Summer (May – October)	Winter (November - April)
On-Peak	$0.032950	$0.028980
Shoulder-Peak	$0.020450	N/A
Off-Peak	$0.023270	$0.016480

The Summer periods below are for Monday through Sunday (excluding Memorial Day, Independence Day and Labor Day):

On-Peak is 2:00 p.m. to 6:00 p.m.

Shoulder-Peak is 12:00 noon to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.

Off-Peak is 8:00 p.m. to 12:00 p.m.

The Winter periods below are for Monday through Sunday (excluding Thanksgiving Day, Christmas Day and New Year's Day):

On-Peak is 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.

Shoulder-Peak: there are no shoulder peak periods in the winter.

Off-Peak is 10:00 a.m. to 5:00 p.m. and 9:00 p.m. to 6:00 a.m.

Generation Capacity, all kWhs $0.000414 per kWh

Fuel and Purchased Power:

	Summer (May – October)	Winter (November - April)
On-Peak	$0.048676	$0.037836
Shoulder-Peak	$0.036176	N/A
Off-Peak	$0.038996	$0.044706

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

PRIMARY SERVICE

The above rate is subject to Primary Service and Metering. The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers

POWER FACTOR ADJUSTMENT

The above rate is subject to a discount or a charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is above or below 90% lagging to a maximum discount of 13.0¢ per kW of billing demand per month.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:

Meter Services	$300.00 per month
Meter Reading	$025.00 per month
Billing & Collection	$150.00 per month
Customer Delivery	$025.00 per month

Energy Charges:

Delivery:

On-peak	$7.00 per kW
Off-peak	$2.33 per kW

	Summer (May – October)	Winter (November - April)
On-Peak	$0.020941	$0.016971
Shoulder-Peak	$0.008441	N/A
Off-Peak	$0.011261	$0.004471

Fixed Must-Run (See Must-Run Generation – Rider No. 2) $0.003655 per kWh

System Benefits $0.000428 per kWh

Transmission $0.006184 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000084 per kWh
Reactive Supply and Voltage Control	$0.000330 per kWh
Regulation and Frequency Response	$0.000320 per kWh
Spinning Reserve Service	$0.000867 per kWh
Supplemental Reserve Service	$0.000141 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity $0.000414 per kWh

Fuel and Purchased Power:

	Summer (May – October)	Winter (November - April)
On-Peak	$0.048676	$0.037836
Shoulder-Peak	$0.036176	N/A
Off-Peak	$0.038996	$0.044706

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;
Transmission and Ancillary Services – Rider No. 3;
Termination Costs Regulatory Asset – Rider No. 4;
Transmission Credit – Rider No. 5.

Pricing Plan PS-40
Municipal Service

AVAILABILITY

Available for Municipal Service where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

Applicable for service to the City of Tucson and City of South Tucson for Municipal buildings and grounds.

Not applicable to resale, breakdown, standby, or auxiliary service or to buildings used for residential purposes.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, at secondary voltage and subject to availability at point of delivery approved by the Company.

RATE

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges:	
Summer (May – October), all kWh	$0.059931
Winter (November – April), all kWh	$0.049931
Generation Capacity, all kWhs	$0.000328
Fuel and Purchased Power:	
Summer (May – October, all kWh	$0.063934
Winter (November – April), all kWh	$0.034866

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy Charges:	
Delivery:	
Summer (May – October, all kWh	$0.048337
Winter (November – April), all kWh	$0.038337
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003308 per kWh

System Benefits	$0.000434 per kWh
Transmission	$0.006129 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000083 per kWh
Reactive Supply and Voltage Control	$0.000327 per kWh
Regulation and Frequency Response	$0.000317 per kWh
Spinning Reserve Service	$0.000860 per kWh
Supplemental Reserve Service	$0.000140 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Generation Capacity	$0.000328 per kWh

Fuel and Purchased Power:

Summer (May – October), all kWh	$0.063934
Winter (November – April), all kWh	$0.034866

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan PS-43
Municipal Water Pumping Service

AVAILABILITY
Available for service to the City of Tucson Water Utility and private water Companies where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Applicable for service to booster stations and wells used for domestic water supply.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE
Single or three phase, 60 Hertz, and at one standard nominal voltage as elected by Customer and subject to availability at point of delivery approved by the Company. Primary metering may be used by mutual agreement.

A monthly net bill at the following rate, plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Energy Charges Firm Service:	
Summer (May – October), all kWh	$0.059931
Winter (November – April), all kWh	$0.049931
Energy Charges Interruptible Service:	
Summer (May – October), all kWh	$0.029931
Winter (November – April), all kWh	$0.028931
Generation Capacity, all kWh	$0.000328
Fuel and Purchased Power Firm Service:	
Summer (May – October), all kWh	$0.049500
Winter (November – April), all kWh	$0.039500
Fuel and Purchased Power Interruptible Service:	
Summer (May – October), all kWh	$0.019500
Winter (November – April), all kWh	$0.019500

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy Charges:

Delivery Firm Service:	
Summer (May – October), all kWh	$0.048337
Winter (November – April), all kWh	$0.038337
Delivery Interruptible Service:	
Summer (May – October), all kWh	$0.018337
Winter (November – April), all kWh	$0.017337
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.003308 per kWh
System Benefits	$0.000434 per kWh
Transmission	$0.006129 per kWh
Transmission Ancillary Services	
System Control & Dispatch	$0.000083 per kWh
Reactive Supply and Voltage Control	$0.000327 per kWh
Regulation and Frequency Response	$0.000317 per kWh
Spinning Reserve Service	$0.000860 per kWh
Supplemental Reserve Service	$0.000140 per kWh
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	

Generation Charges:

Generation Capacity	$0.000328 per kWh
Fuel and Purchased Power Firm Service:	
Summer (May – October), all kWh	$0.049500
Winter (November – April), all kWh	$0.039500
Fuel and Purchased Power Interruptible Service:	
Summer (May – October), all kWh	$0.019500
Winter (November – April), all kWh	$0.019500

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TERMS AND CONDITIONS OF INTERRUPTIBLE SERVICE

1. Customer must furnish, install, own, and maintain at each point of delivery all necessary Company approved equipment which will enable the Company to interrupt service with its master control station.

2. Service may be interrupted by Company during certain periods of the day not exceeding six hours in any 24-hour period.

3. Company will endeavor to give Customer one hour notice of impending interruption; however, service may be interrupted without notice should Company deem such action necessary.

4. The interruptible load shall be separately served and metered and shall at no time be connected to facilities serving Customer's firm load. Conversely, the firm load shall be separately served and metered and shall at no time be connected to facilities serving Customer's interruptible load.

5. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan PS-41
Traffic Signal and Street Lighting Service

AVAILABILITY

Available for service to the State, a county, city, town, political subdivision, improvement district, or a responsible person or persons for unincorporated communities for Traffic Signal and Street Lighting purposes where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

Applicable to Customer owned and maintained traffic signals and public street and highway lighting.

Not applicable to resale, breakdown, standby, or auxiliary service.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery approved by the Company.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

All kWh @ $0.049353 per kWh

Generation Capacity	$0.000168 per kWh
Fuel and Purchased Power:	$0.037991

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Delivery	$0.012455 per kWh
Fixed Must-Run (See Must-Run Generation – Rider No. 2)	$0.002218 per kWh
System Benefits	$0.000408 per kWh
Transmission	$0.026736 per kWh

Transmission Ancillary Services

System Control & Dispatch	$0.000363 per kWh
Reactive Supply and Voltage Control	$0.001427 per kWh
Regulation and Frequency Response	$0.001383 per kWh
Spinning Reserve Service	$0.003750 per kWh
Supplemental Reserve Service	$0.000612 per kWh

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Generation Charges:

Generation Capacity	$0.000168 per kWh
Fuel and Purchased Power:	$0.037991

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan PS-50
Public Street Lighting Service

AVAILABILITY

Available for service for lighting public streets, alleys, thoroughfares, public parks, and playgrounds by use of Company's standard facilities where such service is contracted under this pricing plan by the state, a county, city, town, political subdivision, improvement district, or a responsible person or persons for unincorporated communities.

APPLICABILITY

Applicable to street lighting service from dusk to dawn and Company will own, operate, and maintain the street light system including lamps and globe replacements.

CHARACTER OF SERVICE

Multiple or series street lighting system at option of Company and at one standard nominal voltage.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
per unit per month	$10.33	$10.33	$10.33	$15.51	$23.92	$19.57	$3.61

Note:

The watt high pressure sodium lamps are charged per unit per month.

Per one pole addition and an extension of up to 100 feet of overhead service are charged per pole.

Underground Service is per 100 watt or less high pressure sodium lamp unit per month mounted on standard pole.

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Generation Capacity	$0.0028	$0.0035	$0.0050	$0.0126	$0.0202
Fuel & Purchased Power	$0.6280	$0.7993	$1.1420	$2.8540	$4.5670

Purchased Power Fuel Adjuster Clause ("PPFAC"): The Fuel and Purchased Power Charge shall be subject to a per kWh adjustment to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

STANDARD LAMP UNITS, OVERHEAD SERVICE

(1) The standard 100 watt lamp unit for overhead service is a 9,500 lumen high pressure sodium unit, mounted on a four foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 25 feet above ground level.

(2) The standard 250 watt lamp unit for overhead service is a 27,500 lumen high pressure sodium unit, mounted on an eight foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 27 feet above ground level.

(3) The standard 400 watt lamp unit for overhead service is a 50,000 lumen high pressure sodium unit, mounted on an eighteen foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately 35 feet above ground level.

(4) The standard 100 watt lamp unit for underground service is a 9,500 lumen high pressure sodium post top unit mounted on a pole approximately 15 feet above ground level.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Delivery	$9.72	$9.56	$9.22	$12.75	$19.48
Fixed Must-Run	$0.04	$0.05	$0.07	$0.17	$0.27
System Benefits	$0.01	$0.01	$0.01	$0.03	$0.05
Transmission	$0.44	$0.56	$0.80	$2.01	$3.21
Transmission Ancillary					
System Control & Load Dispatch	$0.01	$0.01	$0.01	$0.03	$0.04
Reactive Supply and Voltage Control	$0.02	$0.03	$0.04	$0.11	$0.17
Regulation and Frequency Response	$0.02	$0.03	$0.04	$0.10	$0.17
Spinning Reserve Service	$0.06	$0.08	$0.11	$0.28	$0.45
Supplemental Reserve Service	$0.01	$0.01	$0.02	$0.05	$0.07
Energy Imbalance Service: currently charged pursuant to the Company's OATT.					
Generation Capacity:	$0.01	$.01	$0.01	$0.01	$0.02
Fuel and Purchased Power	$0.63	$0.80	$1.14	$2.85	$4.57

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this pricing plan will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

SPECIAL PROVISIONS

(1) Installation of a light on an existing pole is subject to prior approval of Company.

(2) For underground service, where customer provides trenching up to 10 feet in accordance with Company's electric service requirements, customer shall be billed at the rates for overhead service.

(3) Extensions beyond 100 feet and all installations other than those addressed in this pricing plan will require specific agreements providing adequate revenue or arrangements for construction financing.

(4) The Customer is not authorized to make connections to this lighting circuit or to make attachments or alterations to the Company owned pole.

(5) If a Customer requests a relocation of a lighting installation, the costs of such relocation must be borne by the Customer.

(6) The Customer is expected to notify the Company when lamp outages occur.

(7) The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

(8) After the minimum contract period, if any, has expired, this agreement shall be extended from year to year unless written notice of desire to terminate is given by either party at least thirty (30) days prior to the end of any such annual extension date.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

The Company's following Riders may apply to this pricing plan:

Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

Pricing Plan GS-51
Private Street and Area Lighting Service

AVAILABILITY
At any point where the Company in its judgment has facilities of adequate capacity and suitable voltage available.

APPLICABILITY
To any Customer for private street or outdoor area lighting where this service can be supplied from existing facilities of the Company.

Service is from dusk to dawn and the Company will install, own, operate, and maintain the complete lighting installation including lamp replacements.

Not applicable to resale service.

CHARACTER OF SERVICE
Multiple or series street lighting system at option of Company and at one standard nominal voltage.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
per unit per month	$10.33	$10.33	$10.33	$15.51	$23.92	$19.57	$3.61

Note:

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Per one pole addition and an extension of up to 100 feet of overhead service are charged per pole.

Underground Service is per 100 watt or less high pressure sodium lamp unit per month mounted on standard pole.

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Generation Capacity	$0.0028	$0.0035	$0.0050	$0.0126	$0.0202
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Transmission	$0.44	$0.56	$0.80	$2.01	$3.21
Transmission Ancillary					
System Control & Load Dispatch	$0.01	$0.01	$0.01	$0.03	$0.04
Reactive Supply and Voltage Control	$0.02	$0.03	$0.04	$0.11	$0.17
Regulation and Frequency Response	$0.02	$0.03	$0.04	$0.10	$0.17
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Generation Capacity:	$0.01	$.01	$0.01	$0.01	$0.02
Fuel and Purchased Power	$0.63	$0.80	$1.14	$2.85	$4.57

DIRECT ACCESS

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A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AISA in Arizona.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

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(8) After the minimum contract period, if any, has expired, this agreement shall be extended from year to year unless written notice of desire to terminate is given by either party at least thirty (30) days prior to the end of any such annual extension date.

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Must-Run Generation – Rider No. 2;

Transmission and Ancillary Services – Rider No. 3;

Termination Costs Regulatory Asset – Rider No. 4;

Transmission Credit – Rider No. 5.

EXHIBIT

DBE-5

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	)	DOCKET NO. E-01933A-05-0650
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 ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. E-01933A-07-____

TUCSON ELECTRIC POWER COMPANY

APPLICATION

TESTIMONY AND EXHIBITS

VOLUME 4 OF 4

July 2, 2007

Direct Testimony of Dr. Kimbugwe Kateregga

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
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IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
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 ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-____

Direct Testimony of

Dr. Kimbugwe A. Kateregga

on Behalf of

Tucson Electric Power Company

July 2, 2007

TABLE OF CONTENTS

I. Qualifications 1

II. Purpose of Testimony 2

III. Development of Depreciation Rates 2

IV. 2007 Depreciation Rate Study 6

Exhibits:

Exhibit KAK-1 2007 Depreciation Rate Study

BEFORE THE
ARIZONA CORPORATION COMMISSION

PREPARED DIRECT TESTIMONY OF
DR. KIMBUGWE A. KATEREGGA

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Kimbugwe A. Kateregga. My business address is 17595 S. Tamiami Trail, Suite 212, Fort Myers, Florida 33908.

Q. WHAT IS YOUR OCCUPATION?

A. I am a Vice President and Consultant of Foster Associates, Inc.

I. QUALIFICATIONS

Q. WOULD YOU BRIEFLY DESCRIBE YOUR EDUCATIONAL TRAINING AND PROFESSIONAL BACKGROUND?

A. I received a B.Sc. (Eng.) degree in Civil Engineering from Makerere University in Uganda and an M.Sc. degree in Management Science from the University of Wales in 1982. I also received a Ph.D. degree in Engineering Valuation from Iowa State University in 1987. The subject of my Masters thesis was forecasting equipment lives and my Doctoral research and dissertation addressed technological forecasting models and their applications in capital recovery. I have made presentations to regulators, committees, and conferences on capital recovery issues, published articles in the field of depreciation and technological forecasting and taught college level mathematics and statistics. I am a member of Phi Kappa Phi, the American Association of Cost Engineers and the Society of Depreciation Professionals.

Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

A. I joined the firm of Foster Associates in 1986 as a Staff Consultant and specialist in depreciation. Prior to joining Foster Associates, I was employed as a Research Assistant at Iowa State University. I served under contract in this capacity between 1983 and 1986 to investigate marginal cost pricing issues and the application of technologi-

cal forecasting models in predicting the service life of industrial property. The findings of this research have been implemented in the telecommunications industry.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have testified in several proceedings before the New York, New Jersey and Montana public service commissions.

II. PURPOSE OF TESTIMONY

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

A. Foster Associates was engaged by Tucson Electric Power Company (TEP) to conduct a 2007 depreciation rate study for a) local generation operations; b) non–local generation operations; and c) distribution and general plant categories. The purpose of my testimony is to sponsor and describe the study conducted by Foster Associates. Depreciation rates currently used by TEP for local generation, distribution and general plant categories were approved by the Arizona Corporation Commission (ACC) pursuant to a settlement agreement in Docket No. U–1933–95–317 (Decision No. 59584, dated March 29, 1996). The approved rates were derived from parameters (*i.e.,* projection lives, projection curves and net salvage rates) estimated in a 1995 depreciation study based on December 31, 1994 plant and depreciation reserve balances.

Depreciation rates currently used for non–local generation assets were developed by Foster Associates in a 2004 Depreciation Rate Study based on December 31, 2003 plant and depreciation reserve balances

III. DEVELOPMENT OF DEPRECIATION RATES

Q. WOULD YOU 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. 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 the 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 firm. 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.

Q. WHAT ARE 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 removal expense. 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 curve. 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 usually obtained from an analysis of the gross salvage and removal expense 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 the net salvage realized in the past. Among the factors which 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 balance in the recorded reserve 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 measure of the status of a company's depreciation practices and procedures. Differences between theoretical and recorded reserves will arise as a normal occurrence when service lives, dispersion patterns and salvage estimates are adjusted in the course of depreciation reviews. Differences will also arise due to plant accounting activity such as transfers and adjustments, which require an identification of reserves at a different level from that maintained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory, to periodically redistribute recorded reserves among primary accounts based on the most recent estimates of service lives, retirement dispersions and net salvage rates. A redistribution of the recorded reserve 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.

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

These 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.

IV. 2007 Depreciation Rate Study

Q. DID TEP PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR CONDUCTING THE 2007 DEPRECIATION STUDY?

A. Yes, they did. The database used in the current study was initially constructed in 2004 when depreciation rates were developed by Foster Associates for non–local generation operations. The 2004 database was updated for the current study by appending additional plant and net salvage transactions for activity years 2004–2006 and age distributions of surviving plant at December 31, 2006. The accuracy and completeness of the assembled database was verified for activity years 1989 through 2006 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. Age distributions of surviving plant at December 31, 2006 were reconciled to the CPR.

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

A. Yes, we did. As discussed in Exhibit KAK-1, all plant accounts were analyzed using a technique in which first, second and third degree polynomials were fitted to a set of observed retirement ratios. The resulting function can be expressed as a survivorship function, which is numerically integrated to obtain an estimate of the average service life. The smoothed survivorship function is 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 curve for each plant category.

Q. DID FOSTER ASSOCIATES CONDUCT A NET SALVAGE ANALYSIS FOR TEP PLANT AND EQUIPMENT?

A. Yes, we did. A five–year moving average analysis of the ratio of realized salvage and removal expense to the associated retirements was used in the 2007 study for distribution and general plant categories to a) estimate a realized net salvage rate; b) detect the emergence of historical trends; and c) establish a basis for estimating a future net salvage rate. 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 for the distribution function and depreciable general plant accounts were estimated using direct–dollar weighting of historical retirements with the historical net salvage rate, and future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate. The computation of the estimated average net salvage rates is shown in Exhibit KAK-1, Statement D.

It should be noted that Foster Associates is recommending a separation of the accrual rate for net salvage from the accrual rate for the investment portion of a plant account. Under this recommendation, depreciation charges for the investment portion of a plant account will be accumulated in primary account investment reserves. Net salvage accruals will be accumulated in function net salvage reserves. The benefits derived from a separate accrual rate for net salvage include reduced field reporting, simplified accounting, and improved monitoring and control of reserve imbalances.

The proposed separation of the net salvage accrual from the investment accrual has not been applied to general plant accounts for which TEP is proposing to retain depreciation accounting. Gross salvage and cost of removal for plant items classified in these accounts are generally identifiable. It is not necessary, therefore, to analyze or estimate net salvage rates at a combined level for these accounts.

Upon approval by the ACC of a settlement agreement in November 1999, TEP discontinued application of Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Cer-

tain Types of Regulation (FAS 71) for its generation operations. Prior to this accounting change, costs for final removal of all owned generation facilities were accrued as a component of depreciation expense. Consistent with the accounting guidance provided in FAS 143 for non–regulated entities not subject to FAS 71, TEP discontinued accruing for cost of removal for its generation operations. Accordingly, net salvage rates were not estimated for local and non–local generation assets in the 2007 depreciation study.

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

A. Yes, we did. Statement C of Exhibit KAK-1 provides a comparison of recorded, computed and redistributed reserves at December 31, 2006. The recorded reserve for local generation operations was $89,182,438 or 51.7 percent of the depreciable plant investment. The corresponding computed reserve is $74,410,080 or 43.1 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $14,772,358 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this study.

The recorded reserve for non–local generation operations was $546,760,278 or 51.3 percent of the depreciable plant investment. The corresponding computed reserve is $372,487,181 or 35.0 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $174,273,097 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this study.

The recorded reserve for distribution and general plant categories was $478,212,361 or 44.2 percent of the depreciable plant investment. The corresponding computed reserve is $348,971,270 or 32.3 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $129,241,092 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this study.

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

A. Yes, we are. 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.

As noted earlier, the current study proposes to segregate the recorded reserve into an investment portion and a net salvage portion, such that net salvage can be accrued and recorded at the function level and depreciation expense (exclusive of net salvage) can be accrued by primary account. A redistribution of the recorded reserve is necessary, therefore, to develop an initial investment reserve balance for each primary account and a net salvage reserve balance for each function consistent with the estimates of retirement dispersion and net salvage rates developed in this study.

A redistribution of reserves is also needed to eliminate reserve imbalances created by a prior adoption of amortization accounting without an initialization of depreciation reserves. The amortization period approved for each account was used to derive a theoretical reserve that will replace the recorded reserve and permit a uniform treatment of embedded plant and future additions. Plant older than the approved amortization periods will be retired from service and future retirements will be posted as each vintage achieves an age equal to the amortization period. The depreciation reserve for the General plant function was redistributed by setting the recorded reserves for the amortization accounts equal to the theoretical reserves derived from the approved amortization periods and distributing the residual imbalances to the remaining depreciable accounts in the General function.

A redistribution of the recorded reserve for distribution accounts was achieved by first segregating the function reserve into an investment portion and a net salvage portion in proportion to the components of the theoretical or computed reserve. A redistribution of the recorded investment reserve to primary accounts was achieved by multiplying the calculated reserve for each primary account within the function by

the ratio of the sum of the recorded reserve to the sum of the calculated reserve. The sum of the redistributed investment reserve and the net salvage reserve is, therefore, equal to the recorded depreciation reserve at the function level before the redistribution. A similar calculation was made to redistribute recorded reserves by unit for local and non–local generation plant accounts.

Q. WOULD YOU PLEASE DESCRIBE THE DEPRECIATION SYSTEM CURRENTLY APPROVED BY THE COMMISSION FOR TEP?

A. With the exception of non–local generation, TEP is currently using depreciation rates developed from a system composed of the straight–line method, broad group procedure, remaining–life technique[1].

The formulation of an account accrual rate using the currently approved depreciation 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 the computed reserve and the recorded reserve are expressed as ratios to the plant in service.

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

A. Yes, we are. Depreciation rates recommended in the 2007 study for all depreciable plant categories were derived from a system composed of the straight–line method, vintage group procedure, remaining–life technique. This change in procedure from

[1] Depreciation rates for non–local generation were developed in the 2004 study using the straight–line method, vintage–group procedure, remaining–life technique.

broad group to vintage group is recommended by Foster Associates to more nearly achieve the goals and objectives of depreciation accounting.

Unlike the broad group procedure in which each vintage is estimated to have the same average service life, consideration is given to the realized life of each vintage when average service lives and remaining lives are derived using the vintage group procedure. The vintage group procedure distinguishes average service lives among vintages and composite life statistics are computed for each plant account. The formulation of an account accrual rate using the straight–line method, vintage group procedure, remaining–life technique is identical to the broad group procedure.

Q. WOULD YOU PLEASE SUMMARIZE THE DEPRECIATION RATES AND ACCRUALS FOSTER ASSOCIATES RECOMMENDED FOR TEP IN THE 2007 STUDY?

A. Table 2 provides a summary of the changes in annual rates and accruals resulting from an application of the parameters and depreciation system recommended in the 2007 study for local generation assets.

	Accrual Rate			2007 Annualized Accrual		
Function	Present	Proposed	Difference	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Steam Production	3.46%	3.84%	0.38%	$3,502,926	$3,891,722	$388,796
Other Production	1.87%	1.98%	0.11%	1,331,846	1,407,639	75,793
Total	2.80%	3.07%	0.27%	$4,834,772	$5,299,361	$464,589

Table 2. Local Generation Assets

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 3.07 percent. Depreciation expense is presently accrued at rates that composite to 2.80 percent. The recommended change in the composite depreciation rate is, therefore, an increase of 0.27 percentage points.

A continued application of current rates would provide annualized depreciation expense of $4,834,772 compared to an annualized expense of $5,299,361 using the rates developed in this study. The proposed 2007 expense increase is $464,589. The computed change in annualized accruals includes a reduction of $834,723 attribut-

able to an amortization of a $14,772,358 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life statistics recommended in the 2007 study.

Table 3 provides a summary of the changes in annual rates and accruals resulting from an application of the parameters recommended in the 2007 study for non–local generation assets.

Function	Accrual Rate			2007 Annualized Accrual		
	Present	Proposed	Difference	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Steam Production	1.86%	2.06%	0.20%	$19,818,591	$21,993,653	$2,175,062
Total	1.86%	2.06%	0.20%	$19,818,591	$21,993,653	$2,175,062

Table 3. Non-Local Generation Assets

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.06 percent. Depreciation expense is presently accrued at rates that composite to 1.86 percent. The recommended change in the composite depreciation rate is, therefore, an increase of 0.20 percentage points.

A continued application of current rates would provide annualized depreciation expense of $19,818,591 compared to an annualized expense of $21,993,653 using the rates developed in this study. The proposed 2007 expense increase is $2,175,062. The computed change in annualized accruals includes a reduction of $5,959,797 attributable to an amortization of a $174,273,097 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life statistics recommended in the 2007 study.

Table 4 provides a summary of the changes in annual rates and accruals resulting from adoption of the parameters and depreciation system recommended in the 2007 study for distribution and general plant categories.

Function	Accrual Rate			2007 Annualized Accrual		
	Present	Proposed	Difference	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Distribution	3.35%	1.82%	-1.53%	$31,173,666	$16,891,056	($14,282,610)
General Plant	7.65%	5.26%	-2.39%	11,610,138	7,983,764	(3,626,374)
Net Salvage		0.28%	0.28%		2,603,350	2,603,350
Total	3.96%	2.54%	-1.42%	$42,783,804	$27,478,170	($15,305,634)

Table 4. Distribution and General Plant

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.54 percent. Depreciation expense is presently accrued at rates that composite to 3.96 percent. The recommended change in the composite depreciation rate is, therefore, a reduction of 1.42 percentage points.

A continued application of current rates would provide annualized depreciation expense of $42,783,804 compared to an annualized expense of $27,478,170 using the rates developed in this study. The proposed 2007 expense decrease is $15,305,634. The computed change in annualized accruals includes a reduction of $5,123,789 attributable to an amortization of a $129,241,092 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life and net salvage parameters recommended in the 2007 study

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

EXHIBIT

KAK-1

Exhibit KAK–1

2007 Depreciation Rate Study

Tucson Electric Power Company

–Local Generation
–Non–Local Generation
–Distribution and General

Prepared by
Foster Associates, Inc.

CONTENTS

EXECUTIVE SUMMARY — SECTION I

INTRODUCTION 1

SCOPE OF STUDY 2

DEPRECIATION SYSTEM 2

PROPOSED DEPRECIATION RATES 4

COMPANY PROFILE — SECTION II

GENERAL 7

GENERATING RESOURCES 7

TRANSMISSION SYSTEM 8

DISTRIBUTION SYSTEM 8

STUDY PROCEDURE — SECTION III

INTRODUCTION 9

SCOPE 9

DATA COLLECTION 9

LIFE ANALYSIS AND ESTIMATION 11

NET SALVAGE ANALYSIS 13

DEPRECIATION RESERVE ANALYSIS 14

DEVELOPMENT OF ACCRUAL RATES 16

STATEMENTS — SECTION IV

INTRODUCTION 18

LOCAL GENERATION

STATEMENT A – REMAINING–LIFE ACCRUAL RATES 19

STATEMENT B – REMAINING–LIFE ACCRUALS 22

STATEMENT C – DEPRECIATION RESERVE SUMMARY 26

STATEMENT E – PRESENT AND PROPOSED PARAMETERS 32

NON–LOCAL GENERATION

STATEMENT A – REMAINING–LIFE ACCRUAL RATES 38

STATEMENT B – REMAINING–LIFE ACCRUALS 42

STATEMENT C – DEPRECIATION RESERVE SUMMARY 46

STATEMENT E – PRESENT AND PROPOSED PARAMETERS 53

DISTRIBUTION AND GENERAL

STATEMENT A – REMAINING–LIFE ACCRUAL RATES 60

STATEMENT B – REMAINING–LIFE ACCRUALS 61

STATEMENT C – DEPRECIATION RESERVE SUMMARY 62

STATEMENT D – AVERAGE NET SALVAGE 64

STATEMENT E – PRESENT AND PROPOSED PARAMETERS 66

ANALYSIS SECTION V

INTRODUCTION 68

SCHEDULE A – GENERATION ARRANGEMENT 68

SCHEDULE B – AGE DISTRIBUTION 69

SCHEDULE C – PLANT HISTORY 70

SCHEDULE D – ACTUARIAL LIFE ANALYSIS 70

SCHEDULE E – GRAPHICS ANALYSIS 71

SCHEDULE F – HISTORICAL NET SALVAGE ANALYSIS 71

DISTRIBUTION

ACCOUNT 365.00 – OVERHEAD CONDUCTORS AND DEVICES

SCHEDULE A – GENERATION ARRANGEMENT 72

SCHEDULE B – AGE DISTRIBUTION 75

SCHEDULE C – PLANT HISTORY 78

SCHEDULE D – ACTUARIAL LIFE ANALYSIS 80

SCHEDULE E – GRAPHICS ANALYSIS 83

SCHEDULE F – HISTORICAL NET SALVAGE ANALYSIS (DISTRIBUTION) 86

EXECUTIVE SUMMARY

INTRODUCTION

This report presents a review and update of depreciation rates and parameters for utility plant owned and operated by Tucson Electric Power Company (TEP). The report contains recommended 2007 depreciation rates and parameters for: a) local generation assets; b) non–local generation assets; and c) electric distribution and general plant categories. Work on the study commenced in January 2007 and progressed through mid–May, at which time the project was completed.

Foster Associates is a public utility economic consulting firm headquartered in Bethesda, Maryland 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, Florida office include property life forecasting, technological 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 for local generation, distribution and general plant categories were approved by the Arizona Corporation Commission (ACC) pursuant to a settlement agreement in Docket No. U–1933–95–317 (Decision No. 59584, dated March 29, 1996). The approved rates were derived from parameters (*i.e.*, projection lives, projection curves and net salvage rates) estimated in a 1995 depreciation study based on December 31, 1994 plant and depreciation reserve balances.

Depreciation rates currently used for non–local generation assets were developed by Foster Associates in a 2004 Depreciation Rate Study based on December 31, 2003 plant and depreciation reserve balances.

The principal findings and recommendations of the 2007 Depreciation Rate Study are summarized in the Section IV of this report. Statement A provides a comparative summary of present and proposed annual depreciation rates for each rate category. Statement B provides a comparison of present 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 components used to obtain weighted–average net salvage rates. Statement E provides a comparative summary of present and proposed pa-

rameters including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates. The report contains a set of statements for: a) local generation; b) non–local generation; and c) distribution and general plant categories.

SCOPE OF STUDY

The principal activities undertaken in the course of the current study included:

- Collection of plant and net salvage data;
- Reconciliation of data to the official records of the Company;
- Discussions with TEP operations and plant accounting 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 non–local generation, TEP is currently using depreciation rates developed from a system composed of the straight–line method, broad group procedure, remaining–life technique[1]. Depreciation rates recommended in the 2007 study for all depreciable plant categories were derived from a system composed of the straight–line method, vintage group procedure remaining–life technique. This change in procedure from broad group to vintage group is recommended by Foster Associates to more nearly achieve the goals and objectives of depreciation accounting.

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

[1]Depreciation rates for non–local generation were developed in the 2004 study using the straight–line method, vintage–group procedure, remaining–life technique.

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 can be more nearly achieved using the vintage group procedure combined with the remaining–life technique. Unlike the broad group procedure in which each vintage is estimated to have the same average service life, the vintage group procedure distinguishes average service lives among vintages and provides cost apportionment over the estimated weighted–average remaining life or average life of a rate category.

The level of asset grouping identified in the broad group procedure is the total plant in service from all vintages in an account. Each vintage is estimated to have the same average service life. It is unlikely, therefore, that compensating deviations (*i.e.*, over and underestimates of average service life) will be created among vintages to achieve cost allocation over the average service life of each vintage.

The level of asset grouping identified in the vintage group procedure is the plant in service from each vintage. The average service life (or remaining life) is estimated independently for each vintage and composite life statistics are computed for each plant account. It is more likely that compensating deviations will be created with a vintage group procedure than with a broad group procedure.

Foster Associates is also recommending a change in the treatment of net salvage for TEP's distribution functions. The treatment recommended in this study is intended to align net salvage accruals with the accounting source of realized salvage and removal expense for this function.

As a practical matter, it is often difficult for a utility to identify net salvage proceeds by primary account. Amounts reported as net salvage are most often derived from allocations or direct assignments of labor, materials and overheads accumulated under authorized retirement work orders. The accuracy of these estimates is dependent upon field personnel reporting exceptions to standard job procedures and maintaining time sheets with an association of work activities to primary plant accounts. It is for these reasons that companies may elect to record realized salvage and removal expense at the function level rather than by primary account.

These reasons also provide the motivation in this study to recommend a separation of the accrual rate for net salvage from the accrual rate for the investment portion of a plant account. Under this recommendation, depreciation charges for the investment portion of a plant account will be accumulated in primary account investment reserves. Net salvage accruals will be accumulated in a function net salvage reserve. The benefits derived from a separate accrual rate for net salvage include reduced field reporting, simplified accounting, and improved monitoring and control of reserve imbalances.

The proposed separation of the net salvage accrual from the investment accrual has not been applied to general plant accounts for which TEP is proposing to retain depreciation accounting. Gross salvage and cost of removal for plant items classified in these accounts are generally identifiable. It is not necessary, therefore, to analyze or estimate net salvage rates at a combined level for these accounts.

Upon approval by the ACC of a settlement agreement in November 1999, TEP discontinued application of Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation (FAS 71) for its generation operations. Prior to this accounting change, costs for final removal of all owned generation facilities were accrued as a component of depreciation expense. Consistent with the accounting guidance provided in FAS 143 for non–regulated entities not subject to FAS 71, TEP discontinued accruing for cost of removal for its generation operations. Accordingly, net salvage rates were not estimated for local and non–local generation assets in the 2007 depreciation study.

PROPOSED DEPRECIATION RATES

Table 1 provides a summary of the changes in annual rates and accruals resulting from an application of the parameters and depreciation system recommended in the 2007 study for local generation assets.

	Accrual Rate			2007 Annualized Accrual		
Function	Present	Proposed	Difference	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Steam Production	3.46%	3.84%	0.38%	$3,502,926	$3,891,722	$388,796
Other Production	1.87%	1.98%	0.11%	1,331,846	1,407,639	75,793
Total	2.80%	3.07%	0.27%	$4,834,772	$5,299,361	$464,589

Table 1. Local Generation Assets

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 3.07 percent. Depreciation expense is presently accrued at rates that composite to 2.80 percent. The recommended change in the composite depreciation rate is, therefore, an increase of 0.27 percentage points.

A continued application of current rates would provide annualized depreciation expense of $4,834,772 compared to an annualized expense of $5,299,361 using the rates developed in this study. The proposed 2007 expense increase is $464,589. The computed change in annualized accruals includes a reduction of $834,723 attributable to an amortization of a $14,772,358 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life statistics recommended in the 2007 study.

Of the 65 local generation plant accounts included in the 2007 study, Foster

Associates is recommending rate reductions for 23 accounts and rate increases for 42 accounts.

Table 2 provides a summary of the changes in annual rates and accruals resulting from an application of the parameters recommended in the 2007 study for non–local generation assets.

Function	Accrual Rate			2007 Annualized Accrual		
	Present	Proposed	Difference	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Steam Production	1.86%	2.06%	0.20%	$19,818,591	$21,993,653	$2,175,062
Total	1.86%	2.06%	0.20%	$19,818,591	$21,993,653	$2,175,062

Table 2. Non-Local Generation Assets

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.06 percent. Depreciation expense is presently accrued at rates that composite to 1.86 percent. The recommended change in the composite depreciation rate is, therefore, an increase of 0.20 percentage points.

A continued application of current rates would provide annualized depreciation expense of $19,818,591 compared to an annualized expense of $21,993,653 using the rates developed in this study. The proposed 2007 expense increase is $2,175,062. The computed change in annualized accruals includes a reduction of $5,959,797 attributable to an amortization of a $174,273,097 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life statistics recommended in the 2007 study.

Of the 72 non–local generation plant accounts included in the 2007 study, Foster Associates is recommending rate reductions for 31 accounts and rate increases for 41 accounts.

Table 3 provides a summary of the changes in annual rates and accruals resulting from adoption of the parameters and depreciation system recommended in the 2007 study for distribution and general plant categories.

Function	Accrual Rate			2007 Annualized Accrual		
	Present	Proposed	Difference	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Distribution	3.35%	1.82%	-1.53%	$31,173,666	$16,891,056	($14,282,610)
General Plant	7.65%	5.26%	-2.39%	11,610,138	7,983,764	(3,626,374)
Net Salvage		0.28%	0.28%		2,603,350	2,603,350
Total	3.96%	2.54%	-1.42%	$42,783,804	$27,478,170	($15,305,634)

Table 3. Distribution and General Plant

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.54 percent. Depreciation expense is presently accrued at rates that composite to 3.96 percent. The recommended change in the composite depreciation rate is, therefore, a reduction of 1.42 percentage points.

A continued application of current rates would provide annualized depreciation expense of $42,783,804 compared to an annualized expense of $27,478,170 using the rates developed in this study. The proposed 2007 expense decrease is $15,305,634. The computed change in annualized accruals includes a reduction of $5,123,789 attributable to an amortization of a $129,241,092 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life and net salvage parameters recommended in the 2007 study.

Of the 30 distribution and general plant accounts included in the 2007 study, Foster Associates is recommending rate reductions for 27 accounts and rate increases for 3 accounts.

COMPANY PROFILE

GENERAL

TEP is a vertically integrated utility that provides regulated electric service to more than 392,000 retail customers in Southeastern Arizona. TEP's service territory consists of a 1,155 square mile area and includes a population of approximately 1 million in the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP holds a franchise to provide electric distribution service to customers in the Cities of Tucson and South Tucson. These franchises expire in 2026 and 2017, respectively. TEP also sells electricity to other utilities and power marketing entities in the Western U.S. TEP provides electric utility service to a diverse group of residential, commercial, industrial, and public sector customers. Major industries served include copper mining, cement manufacturing, defense, health care, education, military bases and other governmental entities.

GENERATING RESOURCES

At December 31, 2006, TEP owned or leased 2,194 MW of net generating capability, as set forth in Table 4.

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	380	TEP	100.0	380
Springerville Station	2	1990	Coal	380	TEP	100.0	380
San Juan Station	1	1973	Coal	327	PNM	50.0	164
San Juan Station	2	1980	Coal	316	PNM	50.0	158
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	784	APS	7.0	55
Four Corners Station	5	1970	Coal	784	APS	7.0	55
Luna Energy Facility	1	2006	Gas	570	PNM	33.0	190
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 [1]	4	1967	Coal/Gas	156	TEP	100.0	156
Internal Combustion Turbines		1972	Gas/Oil	122	TEP	100.0	122
Internal Combustion Turbines		2001	Gas	95	TEP	100.0	95
Solar Electric Generation		2002-2005	Solar	5	TEP	100.0	5
Total TEP Capacity [2]							2,194

Table 4. Generating Resources

[1] Leased assets.

[2] Excludes 719 MW of additional resources consisting of capacity purchases and interruptible retail load. At December 31, 2006, total owned capacity was 1,658 MW and leased capacity was 536 MW.

TRANSMISSION SYSTEM

TEP has transmission access and power transaction arrangements with over 120 electric systems or suppliers. TEP is taking steps to increase the capacity and reliability of its transmission and distribution system. In 2004, TEP completed a 500 kV connection that increased its energy import capability from the region, allowing TEP to decrease the use of its less efficient gas generating units in favor of more economical purchases of energy in the wholesale market. TEP also has various ongoing projects that are designed to increase access to the regional wholesale energy market and improve the reliability and efficiency of its existing transmission and distribution systems.

As of December 31, 2006, TEP owned or participated in an overhead electric transmission system consisting of:

- 512 circuit–mile of 500 kV lines;
- 1,098 circuit–miles of 345 kV lines;
- 365 circuit–miles of 138 kV lines; and
- 437 circuit–miles of 46 kV lines.

DISTRIBUTION SYSTEM

The overhead electric distribution system is comprised of 2,631 circuit–miles of lower voltage primary lines. TEP owns approximately 60% of the poles on which the lower voltage lines are located. The underground electric distribution system is comprised of 4,201 cable-miles. Electric substation capacity consisted of 101 substations with a total installed transformer capacity of 6,738,947 kilovolt amperes.

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 the depreciation rates used by TEP for its local generation, non–local generation, distribution and general plant categories. 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 2007 study for TEP 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. The age distribution of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the 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 database. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to 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 used by TEP provides aged transactions for all plant accounts.

Service life statistics estimated in this study were derived from plant accounting transactions recorded over the period 1989 through 2006. Detailed accounting transactions were extracted from the CPR system and assigned transaction codes which describe the nature of the accounting activity. Transaction codes for plant additions, for example, were used to distinguish normal additions from acquisitions, purchases, reimbursements and adjustments. Similar transaction codes were used to distinguish normal retirements from sales, reimbursements, abnormal retirements and adjustments. Transaction codes were also assigned to transfers, capital leases, gross salvage, cost of removal and other accounting activity which should be considered in a depreciation study.

The database used in the current 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 for the current study by appending additional plant and net salvage transactions for activity years 2004–2006 and age distributions of surviving plant at December 31, 2006. The accuracy and completeness of the assembled database was verified for activity years 1989 through 2006 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. Age distributions of surviving plant at December 31, 2006 were reconciled to the CPR.

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 the account. The mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

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.

The 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 2007 TEP depreciation study.

An actuarial life analysis program designed and developed by Foster Associates was used in this 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 shows the age of each survivor and the age of each retirement from a group of 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. This so–

called "retirement ratio" (or set of ratios) 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 this study are the Iowa–type curves which are mathematically described in terms of the Pearson frequency curve family. The observed life table was 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 function can be expressed in as a survivorship function which is numerically integrated to obtain an estimate of the projection life. The smoothed survivorship function is 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.

The set of computer programs used in this analysis 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 Foster Associates actuarial life analysis program 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 tabular and graphics output as an 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), the concept of retirement dispersion is applied differently for plant categories composed of major items of plant that will most likely be retired as a single unit. Plant retirements from an integrated system prior to the retirement of the entire facility are more properly 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. All plant accounts for local and non–local generation classified as Steam or Other Production were identified by unit and treated as life-span categories in the 2007 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.

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 an appropriate basis for estimating future salvage and cost of removal. However, consideration should also 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 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.

A five–year moving average analysis of the ratio of realized salvage and removal expense to the associated retirements was used in the 2007 study for distribution and general plant categories to a) estimate a realized net salvage rate; b) detect the emergence of historical trends; and c) establish a basis for estimating a future net salvage rate. 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 for the distribution function and depreciable gen-

eral plant accounts were estimated using direct dollar weighting of historical retirements with the historical net salvage rate, and future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate. The computation of the estimated average net salvage rates is shown in Statement D.

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 presently 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 classifications, the sum of all reserves is the most important measure of the status of a company's depreciation practices. If statistical life studies have not been conducted or retirement dispersion has been ignored 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 a theoretical reserve and a recorded reserve also will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. 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.

It is the opinion of Foster Associates that a redistribution of recorded reserves is 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.

The current study proposes to segregate the recorded reserve into an investment portion and a net salvage portion, such that net salvage can be accrued and recorded at the function level and depreciation expense (exclusive of net salvage) can be accrued by primary account. A redistribution of the recorded reserve is necessary, therefore, to develop an initial investment reserve balance for each primary account and a net salvage reserve balance for each function consistent with the estimates of retirement dispersion and net salvage rates developed in this study.

A redistribution of reserves is also needed to eliminate reserve imbalances created by a prior adoption of amortization accounting without an initialization of depreciation reserves. The amortization period approved for each account was used to derive a theoretical reserve that will replace the recorded reserve and permit a uniform treatment of embedded plant and future additions. Plant older than the approved amortization periods will be retired from service and future retirements will be posted as each vintage achieves an age equal to the amortization period. The depreciation reserve for the General plant function was redistributed by setting the recorded reserves for the amortization accounts equal to the theoretical reserves derived from the approved amortization periods and distributing the residual imbalances to the remaining depreciable accounts in the General function.

A redistribution of the recorded reserve for distribution accounts was achieved by first segregating the function reserve into an investment portion and a net salvage portion in proportion to the components of the theoretical or computed reserve. A redistribution of the recorded investment reserve to primary accounts was achieved by multiplying the calculated reserve for each primary account within the function by the ratio of the sum of the recorded reserve to the sum of the calculated reserve. The sum of the redistributed investment reserve and the net salvage reserve is, therefore, equal to the recorded depreciation reserve at the function level before the redistribution. A similar calculation was made to redistribute recorded reserves by unit for local and non–local generation plant accounts.

Statement C provides a comparison of recorded, computed and redistributed

reserves at December 31, 2006. The recorded reserve for local generation operations was $89,182,438 or 51.7 percent of the depreciable plant investment. The corresponding computed reserve is $74,410,080 or 43.1 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $14,772,358 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this study.

The recorded reserve for non–local generation operations was $546,760,278 or 51.3 percent of the depreciable plant investment. The corresponding computed reserve is $372,487,181 or 35.0 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $174,273,097 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this study.

The recorded reserve for distribution and general plant categories was $478,212,361 or 44.2 percent of the depreciable plant investment. The corresponding computed reserve is $348,971,270 or 32.3 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $129,241,092 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this study.

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 using a time–based method is that it does not require an estimate of the remaining amount of service capacity an asset will provide or the amount of capacity actually consumed during an accounting interval. Using a time–based allocation method, however, does not alter the goal of depreciation accounting. If it is predictable 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 2007 study were developed using a 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 combined with an amortization of reserve imbalances over the estimated remaining life of each rate category. 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. 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 retained in this study for selected General support assets is consistent with the goals and objectives of depreciation derived from the matching and expense recognition principles of accounting. Amortization accounting for these rate categories relieves TEP of the burden of maintaining detailed plant records for numerous plant items in which the unit cost is small in relation to the cost of tracking the disposition of each asset.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and present and proposed service life and net salvage parameters recommended for a) local generation operations; b) non–local generation operations; and c) distribution and general plant categories. The content of these statements is briefly described below.

- Statement A provides a comparative summary of present and proposed annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of present and proposed annualized 2007 depreciation accruals based upon 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, 2006.
- Statement D provides a summary of the components used to obtain weighted average net salvage rates.
- Statement E provides a comparative summary of present and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

Present depreciation accruals shown on Statement B are the product of the plant investment (Column B) and present depreciation rates (Column D) shown on Statement A. These are the effective rates used by the Company for the mix of investments recorded on December 31, 2006. Similarly, proposed depreciation accruals shown on Statements B are the product of the plant investment and proposed depreciation rates (Column I) shown on Statement A. Proposed remaining life accrual rates (Statement A) are given by:

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

This 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.

Statements A through E

TUCSON ELECTRIC POWER COMPANY Statement A

Comparison of Present and Proposed Accrual Rates
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present Rem. Life	Present Fut. Net Salvage	Present Accrual Rate	Proposed Avg. Life	Proposed Rem. Life	Proposed Net Salvage	Proposed Reserve Ratio	Proposed Accrual Rate
A	B	C	D	E	F	G	H	I
STEAM PRODUCTION								
311.00 Structures and Improvements			2.42%		8.72		78.87%	2.97%
312.00 Boiler Plant Equipment			3.92%		9.94		62.62%	4.20%
314.00 Turbogenerator Units			2.94%		14.07		60.04%	3.52%
315.00 Accessory Electric Equipment			3.34%		13.99		51.81%	3.60%
316.00 Miscellaneous Power Plant Equipment			3.41%		13.16		60.58%	3.43%
317.00 Asset Retirement Costs					24.68		7.56%	3.75%
Total Steam Production Plant			3.46%		11.20		62.26%	3.84%
OTHER PRODUCTION								
341.00 Structures and Improvements			2.47%		18.01		48.90%	2.40%
342.00 Fuel Holders and Accessories			2.39%		32.31		17.93%	2.44%
343.00 Prime Movers			1.48%		10.36		46.18%	5.19%
344.00 Generators			1.82%		27.79		35.40%	1.92%
345.00 Accessory Electric Equipment			2.24%		17.82		51.38%	2.26%
346.00 Miscellaneous Power Plant Equipment			2.19%		18.72		53.34%	1.96%
Total Other Production Plant			1.87%		26.47		36.69%	1.98%
TOTAL UTILITY			2.80%		15.99		51.70%	3.07%
STEAM PRODUCTION (by Unit)								
Sundt								
311.00 Structures and Improvements			2.42%		8.72		78.87%	2.97%
312.00 Boiler Plant Equipment			3.92%		9.94		62.62%	4.20%
314.00 Turbogenerator Units			2.94%		14.07		60.04%	3.52%
315.00 Accessory Electric Equipment			3.34%		13.99		51.81%	3.60%
316.00 Miscellaneous Power Plant Equipment			3.41%		13.16		60.58%	3.43%
317.00 Asset Retirement Costs					24.68		7.56%	3.75%
Total Sundt			3.46%		11.20		62.26%	3.84%
Sundt Unit 1								
311.00 Structures and Improvements			0.58%		21.81		83.83%	0.74%
312.00 Boiler Plant Equipment			2.19%		21.84		53.84%	2.11%
314.00 Turbogenerator Units			0.65%		21.61		83.83%	0.74%
315.00 Accessory Electric Equipment			1.00%		21.82		73.54%	1.21%
316.00 Miscellaneous Power Plant Equipment			2.30%		21.83		66.37%	1.54%
317.00 Asset Retirement Costs								
Total Sundt Unit 1			1.53%		21.83		66.37%	1.54%
Sundt Unit 2								
311.00 Structures and Improvements			0.62%		23.68		68.04%	1.35%
312.00 Boiler Plant Equipment			2.45%		23.71		50.22%	2.10%
314.00 Turbogenerator Units			0.94%		23.68		68.22%	1.34%
315.00 Accessory Electric Equipment			1.34%		23.71		52.62%	2.00%
316.00 Miscellaneous Power Plant Equipment			2.77%		23.72		42.00%	2.45%
317.00 Asset Retirement Costs								
Total Sundt Unit 2			1.81%		23.70		56.78%	1.82%
Sundt Unit 3								
311.00 Structures and Improvements			0.68%		24.61		79.23%	0.84%
312.00 Boiler Plant Equipment			1.24%		24.64		65.27%	1.41%
314.00 Turbogenerator Units			1.91%		24.65		53.15%	1.90%
315.00 Accessory Electric Equipment			3.06%		24.67		31.78%	2.77%
316.00 Miscellaneous Power Plant Equipment			2.11%		24.64		61.38%	1.57%
317.00 Asset Retirement Costs					24.68		7.56%	3.75%
Total Sundt Unit 3			1.84%		24.65		53.71%	1.88%

TUCSON ELECTRIC POWER COMPANY Statement A

Comparison of Present and Proposed Accrual Rates
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

	Present			Proposed				
Account Description	Rem. Life	Fut. Net Salvage	Accrual Rate	Avg. Life	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H	I
Sundt Unit 4								
311.00 Structures and Improvements			9.36%		4.47		42.46%	12.87%
312.00 Boiler Plant Equipment			13.20%		4.47		34.97%	14.55%
314.00 Turbogenerator Units			11.41%		4.47		35.58%	14.41%
315.00 Accessory Electric Equipment			7.35%		4.47		51.44%	10.86%
316.00 Miscellaneous Power Plant Equipment			11.06%		4.47		38.45%	13.77%
317.00 Asset Retirement Costs								
Total Sundt Unit 4			12.27%		4.47		35.81%	14.36%
Sundt Coal Conversion								
311.00 Structures and Improvements			3.58%		4.47		81.33%	4.18%
312.00 Boiler Plant Equipment			3.76%		4.47		80.95%	4.26%
314.00 Turbogenerator Units			3.51%		4.47		81.74%	4.09%
315.00 Accessory Electric Equipment			5.27%		4.47		74.57%	5.69%
316.00 Miscellaneous Power Plant Equipment			3.40%		4.47		81.74%	4.09%
317.00 Asset Retirement Costs								
Total Sundt Coal Conversion			3.90%		4.47		80.30%	4.41%
Sundt Coal Handling								
311.00 Structures and Improvements								
312.00 Boiler Plant Equipment			19.22%		4.47		6.82%	20.85%
314.00 Turbogenerator Units								
315.00 Accessory Electric Equipment			1.30%		4.47		4.65%	21.33%
316.00 Miscellaneous Power Plant Equipment								
317.00 Asset Retirement Costs								
Total Sundt Coal Handling			15.84%		4.47		8.41%	20.94%
OTHER PRODUCTION (by Unit)								
DeMoss Petrie Gas Unit 1								
341.00 Structures and Improvements			2.18%		37.52		13.08%	2.32%
342.00 Fuel Holders and Accessories			2.18%		37.52		13.08%	2.32%
343.00 Prime Movers								
344.00 Generators			2.18%		37.52		13.08%	2.32%
345.00 Accessory Electric Equipment			2.18%		37.52		13.08%	2.32%
346.00 Miscellaneous Power Plant Equipment			2.28%		37.53		10.71%	2.38%
Total DeMoss Petrie Gas Unit 1			2.18%		37.52		13.06%	2.32%
Sundt Gas								
341.00 Structures and Improvements			0.41%		10.36		86.12%	1.34%
342.00 Fuel Holders and Accessories			4.29%		10.36		63.17%	3.56%
343.00 Prime Movers			0.42%		10.36		46.75%	5.14%
344.00 Generators			0.95%		10.36		90.51%	0.92%
345.00 Accessory Electric Equipment			1.63%		10.36		83.96%	1.55%
346.00 Miscellaneous Power Plant Equipment			0.48%		10.35		102.96%	-0.29%
Total Sundt Gas			1.05%		10.36		88.91%	1.07%
Sundt Gas Unit 1								
341.00 Structures and Improvements			0.07%		10.36		87.61%	1.20%
342.00 Fuel Holders and Accessories			4.14%		10.36		64.25%	3.45%
343.00 Prime Movers			0.07%		10.36		47.55%	5.06%
344.00 Generators			0.57%		10.35		94.64%	0.52%
345.00 Accessory Electric Equipment			1.04%		10.36		87.88%	1.17%
346.00 Miscellaneous Power Plant Equipment			0.07%		10.35		105.50%	-0.53%
Total Sundt Gas Unit 1			0.65%		10.35		92.97%	0.68%

TUCSON ELECTRIC POWER COMPANY Statement A

Comparison of Present and Proposed Accrual Rates
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

	Present			Proposed				
Account Description	Rem. Life	Fut. Net Salvage	Accrual Rate	Avg. Life	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H	I
Sundt Gas Unit 2								
341.00 Structures and Improvements			0.76%		10.36		84.84%	1.48%
342.00 Fuel Holders and Accessories			4.44%		10.36		62.08%	3.66%
343.00 Prime Movers			0.77%		10.36		45.95%	5.22%
344.00 Generators			1.34%		10.36		86.18%	1.33%
345.00 Accessory Electric Equipment			2.16%		10.36		80.39%	1.89%
346.00 Miscellaneous Power Plant Equipment			0.76%		10.35		101.26%	-0.12%
Total Sundt Gas Unit 2			1.46%		10.36		84.73%	1.47%
North Loop Gas								
341.00 Structures and Improvements			2.66%		11.87		68.44%	2.66%
342.00 Fuel Holders and Accessories			2.20%		37.52		13.07%	2.32%
343.00 Prime Movers			2.18%		10.36		45.80%	5.23%
344.00 Generators			1.66%		24.31		44.82%	2.27%
345.00 Accessory Electric Equipment			2.49%		16.78		50.89%	2.93%
346.00 Miscellaneous Power Plant Equipment			2.28%		12.83		71.20%	2.24%
Total North Loop Gas			1.79%		22.44		46.37%	1.88%
North Loop Gas Unit 1								
341.00 Structures and Improvements			4.10%		10.36		60.97%	3.77%
342.00 Fuel Holders and Accessories								
343.00 Prime Movers			2.09%		10.36		45.89%	5.22%
344.00 Generators			1.20%		10.36		85.70%	1.38%
345.00 Accessory Electric Equipment			3.67%		10.36		64.60%	3.42%
346.00 Miscellaneous Power Plant Equipment			4.21%		10.36		62.46%	3.62%
Total North Loop Gas Unit 1			1.98%		10.36		78.77%	2.05%
North Loop Gas Unit 2								
341.00 Structures and Improvements			1.26%		10.35		89.28%	1.04%
342.00 Fuel Holders and Accessories								
343.00 Prime Movers			1.83%		10.36		46.19%	5.19%
344.00 Generators			0.69%		10.35		93.00%	0.68%
345.00 Accessory Electric Equipment			1.82%		10.36		80.30%	1.90%
346.00 Miscellaneous Power Plant Equipment			0.01%		10.35		103.46%	-0.33%
Total North Loop Gas Unit 2			0.64%		10.35		90.89%	0.88%
North Loop Gas Unit 3								
341.00 Structures and Improvements			1.25%		10.35		87.60%	1.20%
342.00 Fuel Holders and Accessories								
343.00 Prime Movers			2.63%		10.36		45.32%	5.28%
344.00 Generators			0.75%		10.35		92.31%	0.74%
345.00 Accessory Electric Equipment			1.85%		10.36		78.89%	2.04%
346.00 Miscellaneous Power Plant Equipment			0.01%		10.35		101.51%	-0.15%
Total North Loop Gas Unit 3			0.91%		10.35		89.97%	0.97%
North Loop Gas Unit 4								
341.00 Structures and Improvements			2.27%		37.53		10.48%	2.39%
342.00 Fuel Holders and Accessories			2.20%		37.52		13.07%	2.32%
343.00 Prime Movers								
344.00 Generators			2.19%		37.52		13.05%	2.32%
345.00 Accessory Electric Equipment			2.20%		37.52		13.07%	2.32%
346.00 Miscellaneous Power Plant Equipment			2.19%		37.52		13.07%	2.32%
Total North Loop Gas Unit 4			2.19%		37.52		13.04%	2.32%

TUCSON ELECTRIC POWER COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/06 Plant Investment	2007 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
STEAM PRODUCTION				
311.00 Structures and Improvements	$10,046,860	$242,654	$298,331	$55,677
312.00 Boiler Plant Equipment	54,922,617	2,154,107	2,307,523	153,416
314.00 Turbogenerator Units	24,243,970	712,553	852,636	140,083
315.00 Accessory Electric Equipment	11,173,775	373,269	402,484	29,215
316.00 Miscellaneous Power Plant Equipment	596,390	20,343	20,467	124
317.00 Asset Retirement Costs	274,147		10,281	10,281
Total Steam Production Plant	$101,257,759	$3,502,926	$3,891,722	$388,796
OTHER PRODUCTION				
341.00 Structures and Improvements	$1,360,095	$33,566	$32,617	($951)
342.00 Fuel Holders and Accessories	1,164,895	27,837	28,420	583
343.00 Prime Movers	354,045	5,233	18,389	13,156
344.00 Generators	62,855,652	1,142,319	1,206,807	64,488
345.00 Accessory Electric Equipment	4,475,216	100,116	101,013	897
346.00 Miscellaneous Power Plant Equipment	1,038,308	22,773	20,393	(2,380)
Total Other Production Plant	$71,248,211	$1,331,846	$1,407,639	$75,793
TOTAL UTILITY	$172,505,970	$4,834,772	$5,299,361	$464,589
STEAM PRODUCTION (by Unit)				
Sundt				
311.00 Structures and Improvements	$10,046,860	$242,654	$298,331	$55,677
312.00 Boiler Plant Equipment	54,922,617	2,154,107	2,307,523	153,416
314.00 Turbogenerator Units	24,243,970	712,553	852,636	140,083
315.00 Accessory Electric Equipment	11,173,775	373,269	402,484	29,215
316.00 Miscellaneous Power Plant Equipment	596,390	20,343	20,467	124
317.00 Asset Retirement Costs	274,147		10,281	10,281
Total Sundt	$101,257,759	$3,502,926	$3,891,722	$388,796
Sundt Unit 1				
311.00 Structures and Improvements	$2,068,058	$11,995	$15,304	$3,309
312.00 Boiler Plant Equipment	10,537,114	230,763	222,333	(8,430)
314.00 Turbogenerator Units	4,978,412	32,360	36,840	4,480
315.00 Accessory Electric Equipment	1,266,340	12,663	15,323	2,660
316.00 Miscellaneous Power Plant Equipment	132,739	3,053	2,044	(1,009)
317.00 Asset Retirement Costs				
Total Sundt Unit 1	$18,982,663	$290,834	$291,844	$1,010
Sundt Unit 2				
311.00 Structures and Improvements	$1,108,052	$6,870	$14,959	$8,089
312.00 Boiler Plant Equipment	10,144,535	248,541	213,035	(35,506)
314.00 Turbogenerator Units	5,379,936	50,571	72,091	21,520
315.00 Accessory Electric Equipment	1,359,387	18,216	27,188	8,972
316.00 Miscellaneous Power Plant Equipment	119,819	3,319	2,936	(383)
317.00 Asset Retirement Costs				
Total Sundt Unit 2	$18,111,729	$327,517	$330,209	$2,692

TUCSON ELECTRIC POWER COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/06 Plant Investment	2007 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
Sundt Unit 3				
311.00 Structures and Improvements	$1,394,535	$9,483	$11,714	$2,231
312.00 Boiler Plant Equipment	7,894,810	97,896	111,317	13,421
314.00 Turbogenerator Units	10,036,388	191,695	190,691	(1,004)
315.00 Accessory Electric Equipment	5,007,840	153,240	138,717	(14,523)
316.00 Miscellaneous Power Plant Equipment	163,803	3,456	2,572	(884)
317.00 Asset Retirement Costs	274,147		10,281	10,281
Total Sundt Unit 3	$24,771,523	$455,770	$465,292	$9,522
Sundt Unit 4				
311.00 Structures and Improvements	$315,862	$29,565	$40,651	$11,086
312.00 Boiler Plant Equipment	5,841,120	771,028	849,883	78,855
314.00 Turbogenerator Units	3,833,146	437,362	552,356	114,994
315.00 Accessory Electric Equipment	224,373	16,491	24,367	7,876
316.00 Miscellaneous Power Plant Equipment	57,359	6,344	7,898	1,554
317.00 Asset Retirement Costs				
Total Sundt Unit 4	$10,271,860	$1,260,790	$1,475,155	$214,365
Sundt Coal Conversion				
311.00 Structures and Improvements	$5,160,353	$184,741	$215,703	$30,962
312.00 Boiler Plant Equipment	20,279,361	762,504	863,901	101,397
314.00 Turbogenerator Units	16,088	565	658	93
315.00 Accessory Electric Equipment	3,263,296	171,976	185,682	13,706
316.00 Miscellaneous Power Plant Equipment	122,670	4,171	5,017	846
317.00 Asset Retirement Costs				
Total Sundt Coal Conversion	$28,841,768	$1,123,957	$1,270,961	$147,004
Sundt Coal Handling				
311.00 Structures and Improvements				
312.00 Boiler Plant Equipment	225,677	43,375	47,054	3,679
314.00 Turbogenerator Units				
315.00 Accessory Electric Equipment	52,539	683	11,207	10,524
316.00 Miscellaneous Power Plant Equipment				
317.00 Asset Retirement Costs				
Total Sundt Coal Handling	$278,216	$44,058	$58,261	$14,203
OTHER PRODUCTION (by Unit)				
DeMoss Petrie Gas Unit 1				
341.00 Structures and Improvements	$483,671	$10,544	$11,221	$677
342.00 Fuel Holders and Accessories	750,386	16,358	17,409	1,051
343.00 Prime Movers				
344.00 Generators	30,560,746	666,224	709,009	42,785
345.00 Accessory Electric Equipment	824,709	17,979	19,133	1,154
346.00 Miscellaneous Power Plant Equipment	332,738	7,586	7,919	333
Total DeMoss Petrie Gas Unit 1	$32,952,250	$718,691	$764,691	$46,000

TUCSON ELECTRIC POWER COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/06 Plant Investment	2007 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
Sundt Gas				
341.00 Structures and Improvements	$11,090	$46	$149	$103
342.00 Fuel Holders and Accessories	112,888	4,843	4,013	(830)
343.00 Prime Movers	141,618	595	7,279	6,684
344.00 Generators	8,263,470	78,147	75,628	(2,519)
345.00 Accessory Electric Equipment	1,009,518	16,411	15,613	(798)
346.00 Miscellaneous Power Plant Equipment	49,750	241	(142)	(383)
Total Sundt Gas	$9,588,334	$100,283	$102,540	$2,257
Sundt Gas Unit 1				
341.00 Structures and Improvements	$5,545	$4	$67	$63
342.00 Fuel Holders and Accessories	56,444	2,337	1,947	(390)
343.00 Prime Movers	70,809	50	3,583	3,533
344.00 Generators	4,231,667	24,121	22,005	(2,116)
345.00 Accessory Electric Equipment	481,584	5,008	5,635	627
346.00 Miscellaneous Power Plant Equipment	19,906	14	(106)	(120)
Total Sundt Gas Unit 1	$4,865,955	$31,534	$33,131	$1,597
Sundt Gas Unit 2				
341.00 Structures and Improvements	$5,545	$42	$82	$40
342.00 Fuel Holders and Accessories	56,444	2,506	2,066	(440)
343.00 Prime Movers	70,809	545	3,696	3,151
344.00 Generators	4,031,803	54,026	53,623	(403)
345.00 Accessory Electric Equipment	527,934	11,403	9,978	(1,425)
346.00 Miscellaneous Power Plant Equipment	29,844	227	(36)	(263)
Total Sundt Gas Unit 2	$4,722,379	$68,749	$69,409	$660
North Loop Gas				
341.00 Structures and Improvements	$865,334	$22,978	$21,247	($1,731)
342.00 Fuel Holders and Accessories	301,621	6,636	6,998	362
343.00 Prime Movers	212,427	4,638	11,110	6,472
344.00 Generators	24,031,436	397,948	422,170	24,222
345.00 Accessory Electric Equipment	2,640,989	65,726	66,267	541
346.00 Miscellaneous Power Plant Equipment	655,820	14,946	12,616	(2,330)
Total North Loop Gas	$28,707,627	$512,872	$540,408	$27,536
North Loop Gas Unit 1				
341.00 Structures and Improvements	$396,584	$16,260	$14,951	($1,309)
342.00 Fuel Holders and Accessories				
343.00 Prime Movers	70,809	1,480	3,696	2,216
344.00 Generators	3,604,298	43,252	49,739	6,487
345.00 Accessory Electric Equipment	747,678	27,440	25,571	(1,869)
346.00 Miscellaneous Power Plant Equipment	306,369	12,898	11,091	(1,807)
Total North Loop Gas Unit 1	$5,125,738	$101,330	$105,048	$3,718

TUCSON ELECTRIC POWER COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/06 Plant Investment	2007 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
North Loop Gas Unit 2				
341.00 Structures and Improvements	$193,230	$2,435	$2,010	($425)
342.00 Fuel Holders and Accessories				
343.00 Prime Movers	70,809	1,296	3,675	2,379
344.00 Generators	3,209,424	22,145	21,824	(321)
345.00 Accessory Electric Equipment	461,617	8,401	8,771	370
346.00 Miscellaneous Power Plant Equipment	128,559	13	(424)	(437)
Total North Loop Gas Unit 2	$4,063,639	$34,290	$35,856	$1,566
North Loop Gas Unit 3				
341.00 Structures and Improvements	$193,231	$2,415	$2,319	($96)
342.00 Fuel Holders and Accessories				
343.00 Prime Movers	70,809	1,862	3,739	1,877
344.00 Generators	3,091,437	23,186	22,877	(309)
345.00 Accessory Electric Equipment	460,658	8,522	9,397	875
346.00 Miscellaneous Power Plant Equipment	128,559	13	(193)	(206)
Total North Loop Gas Unit 3	$3,944,694	$35,998	$38,139	$2,141
North Loop Gas Unit 4				
341.00 Structures and Improvements	$82,289	$1,868	$1,967	$99
342.00 Fuel Holders and Accessories	301,621	6,636	6,998	362
343.00 Prime Movers				
344.00 Generators	14,126,277	309,365	327,730	18,365
345.00 Accessory Electric Equipment	971,036	21,363	22,528	1,165
346.00 Miscellaneous Power Plant Equipment	92,333	2,022	2,142	120
Total North Loop Gas Unit 4	$15,573,556	$341,254	$361,365	$20,111

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
STEAM PRODUCTION							
311.00 Structures and Improvements	$10,046,860	$8,307,357	82.69%	$6,841,205	68.09%	$7,923,511	78.87%
312.00 Boiler Plant Equipment	54,922,617	33,278,665	60.59%	30,456,413	55.45%	34,393,847	62.62%
314.00 Turbogenerator Units	24,243,970	15,394,357	63.50%	11,613,904	47.90%	14,554,870	60.04%
315.00 Accessory Electric Equipment	11,173,775	5,626,540	50.35%	4,888,618	43.75%	5,789,455	51.81%
316.00 Miscellaneous Power Plant Equipment	596,390	308,065	51.65%	301,070	50.48%	361,284	60.58%
317.00 Asset Retirement Costs	274,147	128,711	46.95%	14,816	5.40%	20,729	7.56%
Total Steam Production Plant	$101,257,759	$63,043,695	62.26%	$54,116,027	53.44%	$63,043,695	62.26%
OTHER PRODUCTION							
341.00 Structures and Improvements	$1,360,095	$636,836	46.82%	$505,857	37.19%	$665,049	48.90%
342.00 Fuel Holders and Accessories	1,164,895	197,799	16.98%	175,496	15.07%	208,902	17.93%
343.00 Prime Movers	354,045	347,068	98.03%	120,718	34.10%	163,496	46.18%
344.00 Generators	62,855,652	22,186,621	35.30%	17,338,047	27.58%	22,248,016	35.40%
345.00 Accessory Electric Equipment	4,475,216	2,256,626	50.42%	1,735,093	38.77%	2,299,492	51.38%
346.00 Miscellaneous Power Plant Equipment	1,038,308	513,793	49.48%	418,843	40.34%	553,786	53.34%
Total Other Production Plant	$71,248,211	$26,138,743	36.69%	$20,294,053	28.48%	$26,138,743	36.69%
TOTAL UTILITY	$172,505,970	$89,182,438	51.70%	$74,410,080	43.13%	$89,182,438	51.70%
STEAM PRODUCTION (by Unit)							
Sundt							
311.00 Structures and Improvements	$10,046,860	$8,307,357	82.69%	$6,841,205	68.09%	$7,923,511	78.87%
312.00 Boiler Plant Equipment	54,922,617	33,278,665	60.59%	30,456,413	55.45%	34,393,847	62.62%
314.00 Turbogenerator Units	24,243,970	15,394,357	63.50%	11,613,904	47.90%	14,554,870	60.04%
315.00 Accessory Electric Equipment	11,173,775	5,626,540	50.35%	4,888,618	43.75%	5,789,455	51.81%
316.00 Miscellaneous Power Plant Equipment	596,390	308,065	51.65%	301,070	50.48%	361,284	60.58%
317.00 Asset Retirement Costs	274,147	128,711	46.95%	14,816	5.40%	20,729	7.56%
Total Sundt	$101,257,759	$63,043,695	62.26%	$54,116,027	53.44%	$63,043,695	62.26%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

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 Unit 1							
311.00 Structures and Improvements	$2,068,058	$1,807,844	87.42%	$1,216,551	58.83%	$1,733,672	83.83%
312.00 Boiler Plant Equipment	10,537,114	5,466,055	51.87%	3,980,688	37.78%	5,672,764	53.84%
314.00 Turbogenerator Units	4,978,412	4,282,296	86.02%	2,928,588	58.83%	4,173,448	83.83%
315.00 Accessory Electric Equipment	1,266,340	976,393	77.10%	653,531	51.61%	931,329	73.54%
316.00 Miscellaneous Power Plant Equipment	132,739	66,724	50.27%	61,821	46.57%	88,100	66.37%
317.00 Asset Retirement Costs							
Total Sundt Unit 1	$18,982,663	$12,599,312	66.37%	$8,841,179	46.58%	$12,599,312	66.37%
Sundt Unit 2							
311.00 Structures and Improvements	$1,108,052	$945,423	85.32%	$625,989	56.49%	$753,890	68.04%
312.00 Boiler Plant Equipment	10,144,535	4,227,187	41.67%	4,230,423	41.70%	5,094,772	50.22%
314.00 Turbogenerator Units	5,379,936	4,177,526	77.65%	3,047,514	56.65%	3,670,174	68.22%
315.00 Accessory Electric Equipment	1,359,387	898,429	66.09%	593,985	43.70%	715,347	52.62%
316.00 Miscellaneous Power Plant Equipment	119,819	35,936	29.99%	41,782	34.87%	50,319	42.00%
317.00 Asset Retirement Costs							
Total Sundt Unit 2	$18,111,729	$10,284,501	56.78%	$8,539,694	47.15%	$10,284,501	56.78%
Sundt Unit 3							
311.00 Structures and Improvements	$1,394,535	$1,158,419	83.07%	$789,679	56.63%	$1,104,837	79.23%
312.00 Boiler Plant Equipment	7,894,810	5,467,201	69.25%	3,683,333	46.66%	5,153,335	65.27%
314.00 Turbogenerator Units	10,036,388	5,275,383	52.56%	3,812,565	37.99%	5,334,142	53.15%
315.00 Accessory Electric Equipment	5,007,840	1,197,301	23.91%	1,137,432	22.71%	1,591,376	31.78%
316.00 Miscellaneous Power Plant Equipment	163,803	77,950	47.59%	71,864	43.87%	100,545	61.38%
317.00 Asset Retirement Costs	274,147	128,711	46.95%	14,816	5.40%	20,729	7.56%
Total Sundt Unit 3	$24,771,523	$13,304,964	53.71%	$9,509,690	38.39%	$13,304,964	53.71%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Sundt Unit 4							
311.00 Structures and Improvements	$315,862	$168,097	53.22%	$178,250	56.43%	$134,130	42.46%
312.00 Boiler Plant Equipment	5,841,120	1,696,434	29.04%	2,714,197	46.47%	2,042,387	34.97%
314.00 Turbogenerator Units	3,833,146	1,645,892	42.94%	1,812,608	47.29%	1,363,956	35.58%
315.00 Accessory Electric Equipment	224,373	141,879	63.23%	153,393	68.37%	115,426	51.44%
316.00 Miscellaneous Power Plant Equipment	57,359	25,649	44.72%	29,307	51.09%	22,053	38.45%
317.00 Asset Retirement Costs							
Total Sundt Unit 4	$10,271,860	$3,677,952	35.81%	$4,887,755	47.58%	$3,677,952	35.81%
Sundt Coal Conversion							
311.00 Structures and Improvements	$5,160,353	$4,227,573	81.92%	$4,030,736	78.11%	$4,196,983	81.33%
312.00 Boiler Plant Equipment	20,279,361	16,412,959	80.93%	15,764,981	77.74%	16,415,204	80.95%
314.00 Turbogenerator Units	16,088	13,261	82.43%	12,629	78.50%	13,150	81.74%
315.00 Accessory Electric Equipment	3,263,296	2,403,541	73.65%	2,337,142	71.62%	2,433,536	74.57%
316.00 Miscellaneous Power Plant Equipment	122,670	101,805	82.99%	96,295	78.50%	100,267	81.74%
317.00 Asset Retirement Costs							
Total Sundt Coal Conversion	$28,841,768	$23,159,140	80.30%	$22,241,783	77.12%	$23,159,140	80.30%
Sundt Coal Handling							
311.00 Structures and Improvements							
312.00 Boiler Plant Equipment	225,677	8,829	3.91%	82,791	36.69%	15,385	6.82%
314.00 Turbogenerator Units							
315.00 Accessory Electric Equipment	52,539	8,996	17.12%	13,135	25.00%	2,441	4.65%
316.00 Miscellaneous Power Plant Equipment							
317.00 Asset Retirement Costs							
Total Sundt Coal Handling	$278,216	$17,826	6.41%	$95,926	34.48%	$17,826	6.41%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

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
OTHER PRODUCTION (by Unit)							
DeMoss Petrie Gas Unit 1							
341.00 Structures and Improvements	$483,671	$62,914	13.01%	$56,775	11.74%	$63,276	13.08%
342.00 Fuel Holders and Accessories	750,386	97,607	13.01%	88,083	11.74%	98,169	13.08%
343.00 Prime Movers		49,646					
344.00 Generators	30,560,746	3,955,317	12.94%	3,587,347	11.74%	3,998,105	13.08%
345.00 Accessory Electric Equipment	824,709	107,275	13.01%	96,808	11.74%	107,892	13.08%
346.00 Miscellaneous Power Plant Equipment	332,738	30,320	9.11%	31,976	9.61%	35,637	10.71%
Total DeMoss Petrie Gas Unit 1	$32,952,250	$4,303,079	13.06%	$3,860,989	11.72%	$4,303,079	13.06%
Sundt Gas							
341.00 Structures and Improvements	$11,090	$10,606	95.64%	$6,966	62.81%	$9,551	86.12%
342.00 Fuel Holders and Accessories	112,888	62,078	54.99%	52,007	46.07%	71,307	63.17%
343.00 Prime Movers	141,618	135,453	95.65%	48,287	34.10%	66,206	46.75%
344.00 Generators	8,263,470	7,432,634	89.95%	5,449,934	65.95%	7,479,280	90.51%
345.00 Accessory Electric Equipment	1,009,518	837,209	82.93%	618,413	61.26%	847,630	83.96%
346.00 Miscellaneous Power Plant Equipment	49,750	47,216	94.91%	37,485	75.35%	51,221	102.96%
Total Sundt Gas	$9,588,334	$8,525,196	88.91%	$6,213,092	64.80%	$8,525,196	88.91%
Sundt Gas Unit 1							
341.00 Structures and Improvements	$5,545	$5,506	99.29%	$3,483	62.81%	$4,858	87.61%
342.00 Fuel Holders and Accessories	56,444	31,919	56.55%	26,004	46.07%	36,267	64.25%
343.00 Prime Movers	70,809	70,310	99.29%	24,144	34.10%	33,673	47.55%
344.00 Generators	4,231,667	3,967,460	93.76%	2,871,488	67.86%	4,004,820	94.64%
345.00 Accessory Electric Equipment	481,584	428,889	89.06%	303,462	63.01%	423,233	87.88%
346.00 Miscellaneous Power Plant Equipment	19,906	19,766	99.30%	15,057	75.64%	21,000	105.50%
Total Sundt Gas Unit 1	$4,865,955	$4,523,850	92.97%	$3,243,637	66.66%	$4,523,850	92.97%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

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 2							
341.00 Structures and Improvements	$5,545	$5,100	91.98%	$3,483	62.81%	$4,693	84.64%
342.00 Fuel Holders and Accessories	56,444	30,159	53.43%	26,004	46.07%	35,040	62.08%
343.00 Prime Movers	70,809	65,143	92.00%	24,144	34.10%	32,533	45.95%
344.00 Generators	4,031,803	3,465,174	85.95%	2,578,446	63.95%	3,474,460	86.18%
345.00 Accessory Electric Equipment	527,934	408,320	77.34%	314,951	59.66%	424,397	80.39%
346.00 Miscellaneous Power Plant Equipment	29,844	27,450	91.98%	22,428	75.15%	30,221	101.26%
Total Sundt Gas Unit 2	$4,722,379	$4,001,346	84.73%	$2,969,455	62.88%	$4,001,346	84.73%
North Loop Gas							
341.00 Structures and Improvements	$865,334	$563,316	65.10%	$442,116	51.09%	$592,222	68.44%
342.00 Fuel Holders and Accessories	301,621	38,115	12.64%	35,406	11.74%	39,426	13.07%
343.00 Prime Movers	212,427	161,969	76.25%	72,431	34.10%	97,290	45.80%
344.00 Generators	24,031,436	10,798,670	44.94%	8,300,766	34.54%	10,770,632	44.82%
345.00 Accessory Electric Equipment	2,640,989	1,312,141	49.68%	1,019,872	38.62%	1,343,970	50.89%
346.00 Miscellaneous Power Plant Equipment	655,820	436,257	66.52%	349,382	53.27%	466,928	71.20%
Total North Loop Gas	$28,707,627	$13,310,468	46.37%	$10,219,972	35.60%	$13,310,468	46.37%
North Loop Gas Unit 1							
341.00 Structures and Improvements	$396,584	$221,847	55.94%	$179,656	45.30%	$241,814	60.97%
342.00 Fuel Holders and Accessories							
343.00 Prime Movers	70,809	54,887	77.51%	24,144	34.10%	32,497	45.89%
344.00 Generators	3,604,298	3,140,468	87.13%	2,295,023	63.67%	3,089,055	85.70%
345.00 Accessory Electric Equipment	747,678	452,867	60.57%	358,825	47.99%	482,972	64.60%
346.00 Miscellaneous Power Plant Equipment	306,369	167,625	54.71%	142,169	46.40%	191,357	62.46%
Total North Loop Gas Unit 1	$5,125,738	$4,037,694	78.77%	$2,999,817	58.52%	$4,037,694	78.77%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

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 2							
341.00 Structures and Improvements	$193,230	$166,929	86.39%	$127,356	65.91%	$172,515	89.28%
342.00 Fuel Holders and Accessories							
343.00 Prime Movers	70,809	56,735	80.12%	24,144	34.10%	32,704	46.19%
344.00 Generators	3,209,424	2,971,216	92.58%	2,203,442	68.66%	2,984,749	93.00%
345.00 Accessory Electric Equipment	461,617	370,370	80.23%	273,631	59.28%	370,657	80.30%
346.00 Miscellaneous Power Plant Equipment	128,559	128,378	99.86%	98,187	76.38%	133,003	103.46%
Total North Loop Gas Unit 2	$4,063,639	$3,693,628	90.89%	$2,726,760	67.10%	$3,693,628	90.89%
North Loop Gas Unit 3							
341.00 Structures and Improvements	$193,231	$166,611	86.22%	$127,357	65.91%	$169,268	87.60%
342.00 Fuel Holders and Accessories							
343.00 Prime Movers	70,809	50,347	71.10%	24,144	34.10%	32,089	45.32%
344.00 Generators	3,091,437	2,836,355	91.75%	2,147,034	69.45%	2,853,583	92.31%
345.00 Accessory Electric Equipment	460,658	367,055	79.68%	273,431	59.36%	363,412	78.89%
346.00 Miscellaneous Power Plant Equipment	128,559	128,482	99.94%	98,187	76.38%	130,499	101.51%
Total North Loop Gas Unit 3	$3,944,694	$3,548,851	89.97%	$2,670,153	67.69%	$3,548,851	89.97%
North Loop Gas Unit 4							
341.00 Structures and Improvements	$82,289	$7,928	9.63%	$7,746	9.41%	$8,626	10.48%
342.00 Fuel Holders and Accessories	301,621	38,115	12.64%	35,406	11.74%	39,426	13.07%
343.00 Prime Movers							
344.00 Generators	14,126,277	1,850,632	13.10%	1,655,267	11.72%	1,843,245	13.05%
345.00 Accessory Electric Equipment	971,036	121,850	12.55%	113,984	11.74%	126,929	13.07%
346.00 Miscellaneous Power Plant Equipment	92,333	11,771	12.75%	10,838	11.74%	12,069	13.07%
Total North Loop Gas Unit 4	$15,573,556	$2,030,295	13.04%	$1,823,242	11.71%	$2,030,295	13.04%

TUCSON ELECTRIC POWER COMPANY

Statement E

Proposed Parameters

Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	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
STEAM PRODUCTION												
311.00 Structures and Improvements									27.34	8.72		
312.00 Boiler Plant Equipment									22.31	9.94		
314.00 Turbogenerator Units									27.00	14.07		
315.00 Accessory Electric Equipment									24.88	13.99		
316.00 Miscellaneous Power Plant Equipment									26.57	13.16		
317.00 Asset Retirement Costs									26.09	24.68		
Total Steam Production Plant									24.06	11.20		
OTHER PRODUCTION												
341.00 Structures and Improvements									28.68	18.01		
342.00 Fuel Holders and Accessories									38.04	32.31		
343.00 Prime Movers									15.72	10.36		
344.00 Generators									38.38	27.79		
345.00 Accessory Electric Equipment									29.11	17.82		
346.00 Miscellaneous Power Plant Equipment									31.38	18.72		
Total Other Production Plant									37.01	26.47		
TOTAL UTILITY									28.12	15.99		
STEAM PRODUCTION (by Unit)												
Sundt												
311.00 Structures and Improvements									27.34	8.72		
312.00 Boiler Plant Equipment									22.31	9.94		
314.00 Turbogenerator Units									27.00	14.07		
315.00 Accessory Electric Equipment									24.88	13.99		
316.00 Miscellaneous Power Plant Equipment									26.57	13.16		
317.00 Asset Retirement Costs									26.09	24.68		
Total Sundt									24.06	11.20		

TUCSON ELECTRIC POWER COMPANY

Statement E

Proposed Parameters

Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	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 1												
311.00 Structures and Improvements	2029	SQ					2029	200-SC	52.97	21.81		
312.00 Boiler Plant Equipment	2029	SQ					2029	200-SC	35.10	21.84		
314.00 Turbogenerator Units	2029	SQ					2029	200-SC	52.97	21.81		
315.00 Accessory Electric Equipment	2029	SQ					2029	200-SC	45.09	21.82		
316.00 Miscellaneous Power Plant Equipment	2029	SQ					2029	200-SC	40.86	21.83		
317.00 Asset Retirement Costs												
Total Sundt Unit 1									40.86	21.83		
Sundt Unit 2												
311.00 Structures and Improvements	2031	SQ					2031	200-SC	54.43	23.68		
312.00 Boiler Plant Equipment	2031	SQ					2031	200-SC	40.67	23.71		
314.00 Turbogenerator Units	2031	SQ					2031	200-SC	54.62	23.68		
315.00 Accessory Electric Equipment	2031	SQ					2031	200-SC	42.11	23.71		
316.00 Miscellaneous Power Plant Equipment	2031	SQ					2031	200-SC	36.42	23.72		
317.00 Asset Retirement Costs												
Total Sundt Unit 2									44.85	23.70		
Sundt Unit 3												
311.00 Structures and Improvements	2032	SQ					2032	200-SC	56.74	24.61		
312.00 Boiler Plant Equipment	2032	SQ					2032	200-SC	46.19	24.64		
314.00 Turbogenerator Units	2032	SQ					2032	200-SC	39.75	24.65		
315.00 Accessory Electric Equipment	2032	SQ					2032	200-SC	31.92	24.67		
316.00 Miscellaneous Power Plant Equipment	2032	SQ					2032	200-SC	43.90	24.64		
317.00 Asset Retirement Costs	2032	SQ					2032	200-SC	26.09	24.68		
Total Sundt Unit 3									40.01	24.65		

TUCSON ELECTRIC POWER COMPANY

Statement E

Proposed Parameters

Company Vintage Group Procedure

Account Description	Present Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2006) 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 4												
311.00 Structures and Improvements	2011	SQ					2011	200-SC	10.26	4.47		
312.00 Boiler Plant Equipment	2011	SQ					2011	200-SC	8.35	4.47		
314.00 Turbogenerator Units	2011	SQ					2011	200-SC	8.48	4.47		
315.00 Accessory Electric Equipment	2011	SQ					2011	200-SC	14.13	4.47		
316.00 Miscellaneous Power Plant Equipment	2011	SQ					2011	200-SC	9.14	4.47		
317.00 Asset Retirement Costs												
Total Sundt Unit 4									8.53	4.47		
Sundt Coal Conversion												
311.00 Structures and Improvements	2011	SQ					2011	200-SC	20.42	4.47		
312.00 Boiler Plant Equipment	2011	SQ					2011	200-SC	20.08	4.47		
314.00 Turbogenerator Units	2011	SQ					2011	200-SC	20.79	4.47		
315.00 Accessory Electric Equipment	2011	SQ					2011	200-SC	15.75	4.47		
316.00 Miscellaneous Power Plant Equipment	2011	SQ					2011	200-SC	20.79	4.47		
317.00 Asset Retirement Costs												
Total Sundt Coal Conversion									19.53	4.47		
Sundt Coal Handling												
311.00 Structures and Improvements												
312.00 Boiler Plant Equipment	2011	SQ					2011	200-SC	7.06	4.47		
314.00 Turbogenerator Units												
315.00 Accessory Electric Equipment	2011	SQ					2011	200-SC	5.96	4.47		
316.00 Miscellaneous Power Plant Equipment												
317.00 Asset Retirement Costs												
Total Sundt Coal Handling									6.82	4.47		

TUCSON ELECTRIC POWER COMPANY

Statement E

Proposed Parameters

Company Vintage Group Procedure

Account Description	Present Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2006) 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
OTHER PRODUCTION (by Unit)												
DeMoss Petrie Gas Unit 1												
341.00 Structures and Improvements	2046	SQ					2046	200-SC	42.51	37.52		
342.00 Fuel Holders and Accessories	2046	SQ					2046	200-SC	42.51	37.52		
343.00 Prime Movers												
344.00 Generators	2046	SQ					2046	200-SC	42.51	37.52		
345.00 Accessory Electric Equipment	2046	SQ					2046	200-SC	42.51	37.52		
346.00 Miscellaneous Power Plant Equipment	2046	SQ					2046	200-SC	41.52	37.53		
Total DeMoss Petrie Gas Unit 1									42.50	37.52		
Sundt Gas												
341.00 Structures and Improvements									27.86	10.36		
342.00 Fuel Holders and Accessories									19.21	10.36		
343.00 Prime Movers									15.72	10.36		
344.00 Generators									30.41	10.36		
345.00 Accessory Electric Equipment									26.74	10.36		
346.00 Miscellaneous Power Plant Equipment									41.98	10.35		
Total Sundt Gas									29.42	10.36		
Sundt Gas Unit 1												
341.00 Structures and Improvements	2017	SQ					2017	200-SC	27.86	10.36		
342.00 Fuel Holders and Accessories	2017	SQ					2017	200-SC	19.21	10.36		
343.00 Prime Movers	2017	SQ					2017	200-SC	15.72	10.36		
344.00 Generators	2017	SQ					2017	200-SC	32.20	10.35		
345.00 Accessory Electric Equipment	2017	SQ					2017	200-SC	28.01	10.36		
346.00 Miscellaneous Power Plant Equipment	2017	SQ					2017	200-SC	42.49	10.35		
Total Sundt Gas Unit 1									31.05	10.35		

TUCSON ELECTRIC POWER COMPANY

Statement E

Proposed Parameters

Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	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 Gas Unit 2												
341.00 Structures and Improvements	2017	SQ					2017	200-SC	27.86	10.36		
342.00 Fuel Holders and Accessories	2017	SQ					2017	200-SC	19.21	10.36		
343.00 Prime Movers	2017	SQ					2017	200-SC	15.72	10.36		
344.00 Generators	2017	SQ					2017	200-SC	28.74	10.36		
345.00 Accessory Electric Equipment	2017	SQ					2017	200-SC	25.68	10.36		
346.00 Miscellaneous Power Plant Equipment	2017	SQ					2017	200-SC	41.65	10.35		
Total Sundt Gas Unit 2									27.91	10.36		
North Loop Gas												
341.00 Structures and Improvements									24.27	11.87		
342.00 Fuel Holders and Accessories									42.51	37.52		
343.00 Prime Movers									15.72	10.36		
344.00 Generators									37.13	24.31		
345.00 Accessory Electric Equipment									27.34	16.78		
346.00 Miscellaneous Power Plant Equipment									27.45	12.83		
Total North Loop Gas									34.84	22.44		
North Loop Gas Unit 1												
341.00 Structures and Improvements	2017	SQ					2017	200-SC	18.94	10.36		
342.00 Fuel Holders and Accessories												
343.00 Prime Movers	2017	SQ					2017	200-SC	15.72	10.36		
344.00 Generators	2017	SQ					2017	200-SC	28.52	10.36		
345.00 Accessory Electric Equipment	2017	SQ					2017	200-SC	19.92	10.36		
346.00 Miscellaneous Power Plant Equipment	2017	SQ					2017	200-SC	19.33	10.36		
Total North Loop Gas Unit 1									24.98	10.36		

TUCSON ELECTRIC POWER COMPANY

Statement E

Proposed Parameters

Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	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 2												
341.00 Structures and Improvements	2017	SQ					2017	200-SC	30.36	10.35		
342.00 Fuel Holders and Accessories												
343.00 Prime Movers	2017	SQ					2017	200-SC	15.72	10.36		
344.00 Generators	2017	SQ					2017	200-SC	33.02	10.35		
345.00 Accessory Electric Equipment	2017	SQ					2017	200-SC	25.44	10.36		
346.00 Miscellaneous Power Plant Equipment	2017	SQ					2017	200-SC	43.81	10.35		
Total North Loop Gas Unit 2									31.47	10.35		
North Loop Gas Unit 3												
341.00 Structures and Improvements	2017	SQ					2017	200-SC	30.36	10.35		
342.00 Fuel Holders and Accessories												
343.00 Prime Movers	2017	SQ					2017	200-SC	15.72	10.36		
344.00 Generators	2017	SQ					2017	200-SC	33.88	10.35		
345.00 Accessory Electric Equipment	2017	SQ					2017	200-SC	25.49	10.36		
346.00 Miscellaneous Power Plant Equipment	2017	SQ					2017	200-SC	43.81	10.35		
Total North Loop Gas Unit 3									32.04	10.35		
North Loop Gas Unit 4												
341.00 Structures and Improvements	2046	SQ					2046	200-SC	41.43	37.53		
342.00 Fuel Holders and Accessories	2046	SQ					2046	200-SC	42.51	37.52		
343.00 Prime Movers												
344.00 Generators	2046	SQ					2046	200-SC	42.50	37.52		
345.00 Accessory Electric Equipment	2046	SQ					2046	200-SC	42.51	37.52		
346.00 Miscellaneous Power Plant Equipment	2046	SQ					2046	200-SC	42.51	37.52		
Total North Loop Gas Unit 4									42.50	37.52		

Statements A through E

TUCSON ELECTRIC POWER COMPANY Statement A

Comparison of Present and Proposed Accrual Rates
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present Rem. Life	Present Fut. Net Salvage	Present Accrual Rate	Proposed Avg. Life	Proposed Rem. Life	Proposed Net Salvage	Proposed Reserve Ratio	Proposed Accrual Rate
A	B	C	D	E	F	G	H	I
STEAM PRODUCTION								
310.00 Rights-of-Way	17.39	-3.4%	4.80%		10.52		56.72%	4.16%
311.00 Structures and Improvements	16.73	-3.8%	2.53%		17.87		55.65%	2.74%
312.00 Boiler Plant Equipment	16.73	-3.8%	1.82%		25.12		50.53%	2.05%
314.00 Turbogenerator Units	16.33	-4.5%	1.70%		27.34		50.35%	1.88%
315.00 Accessory Electric Equipment	17.09	-3.6%	1.49%		30.45		52.92%	1.52%
316.00 Miscellaneous Power Plant Equipment	17.09	-3.6%	1.75%		23.73		55.57%	1.95%
317.00 Asset Retirement Cost	15.94	-3.9%	0.95%		22.26		88.56%	0.58%
Total Steam Production Plant			1.86%		24.80		51.31%	2.06%
TOTAL UTILITY			1.86%		24.80		51.31%	2.06%
STEAM PRODUCTION (by Unit)								
Four Corners								
310.00 Rights-of-Way								
311.00 Structures and Improvements	26.50		0.94%		23.71		87.36%	0.53%
312.00 Boiler Plant Equipment	26.51		0.73%		23.71		81.53%	0.78%
314.00 Turbogenerator Units	26.50		0.75%		23.72		73.70%	1.11%
315.00 Accessory Electric Equipment	26.47		0.49%		23.68		96.98%	0.13%
316.00 Miscellaneous Power Plant Equipment	26.53		1.81%		23.73		50.25%	2.09%
317.00 Asset Retirement Cost	26.47		0.46%		23.67		108.12%	-0.34%
Total Four Coners			0.78%		23.71		79.66%	0.86%
Four Corners Unit 4								
310.00 Rights-of-Way								
311.00 Structures and Improvements	26.50		0.90%		23.71		87.85%	0.51%
312.00 Boiler Plant Equipment	26.51		0.68%		23.71		82.92%	0.72%
314.00 Turbogenerator Units	26.50		0.66%		23.72		68.50%	1.33%
315.00 Accessory Electric Equipment	26.47		0.43%		23.68		95.83%	0.18%
316.00 Miscellaneous Power Plant Equipment	26.53		1.81%		23.73		51.08%	2.06%
317.00 Asset Retirement Cost	26.47		0.41%		23.67		112.07%	-0.51%
Total Four Corners Unit 4			0.72%		23.71		80.07%	0.84%
Four Corners Unit 5								
310.00 Rights-of-Way								
311.00 Structures and Improvements	26.50		0.98%		23.70		86.84%	0.58%
312.00 Boiler Plant Equipment	26.51		0.78%		23.71		79.99%	0.84%
314.00 Turbogenerator Units	26.50		0.87%		23.71		81.29%	0.79%
315.00 Accessory Electric Equipment	26.48		0.56%		23.69		98.19%	0.08%
316.00 Miscellaneous Power Plant Equipment	26.53		1.80%		23.73		49.40%	2.13%
317.00 Asset Retirement Cost	26.47		0.52%		23.67		104.52%	-0.19%
Total Four Corners Unit 5			0.83%		23.71		79.19%	0.87%
Navajo								
310.00 Rights-of-Way	21.82		0.40%		18.99		77.78%	1.17%
311.00 Structures and Improvements	21.85		2.37%		19.00		56.14%	2.31%
312.00 Boiler Plant Equipment	21.84		2.28%		19.01		53.87%	2.43%
314.00 Turbogenerator Units	21.84		1.67%		19.00		58.45%	2.19%
315.00 Accessory Electric Equipment	21.83		1.71%		18.99		68.92%	1.63%
316.00 Miscellaneous Power Plant Equipment	21.85		2.20%		19.00		54.60%	2.39%
317.00 Asset Retirement Cost	21.82		1.23%		18.98		77.81%	1.18%
Total Navajo			2.16%		19.01		55.96%	2.32%

TUCSON ELECTRIC POWER COMPANY Statement A

Comparison of Present and Proposed Accrual Rates
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present Rem. Life	Present Fut. Net Salvage	Present Accrual Rate	Proposed Avg. Life	Proposed Rem. Life	Proposed Net Salvage	Proposed Reserve Ratio	Proposed Accrual Rate
A	B	C	D	E	F	G	H	I
Navajo Unit 1								
310.00 Rights-of-Way								
311.00 Structures and Improvements	21.83		1.60%		18.99		75.21%	1.31%
312.00 Boiler Plant Equipment	21.85		2.25%		19.01		52.56%	2.50%
314.00 Turbogenerator Units	21.84		1.61%		19.01		58.81%	2.17%
315.00 Accessory Electric Equipment	21.82		1.28%		18.99		79.34%	1.09%
316.00 Miscellaneous Power Plant Equipment	21.82		1.46%		18.99		75.95%	1.27%
317.00 Asset Retirement Cost	21.82		1.11%		18.98		81.09%	1.00%
Total Navajo Unit 1			2.02%		19.01		57.45%	2.24%
Navajo Unit 2								
310.00 Rights-of-Way								
311.00 Structures and Improvements	21.84		1.26%		19.00		66.30%	1.77%
312.00 Boiler Plant Equipment	21.84		2.25%		19.00		57.81%	2.22%
314.00 Turbogenerator Units	21.84		1.88%		19.00		57.89%	2.22%
315.00 Accessory Electric Equipment	21.84		1.60%		19.00		66.37%	1.77%
316.00 Miscellaneous Power Plant Equipment	21.83		1.57%		18.99		69.35%	1.61%
317.00 Asset Retirement Cost	21.82		1.20%		18.98		77.25%	1.20%
Total Navajo Unit 2			2.08%		19.00		59.01%	2.16%
Navajo Unit 3								
310.00 Rights-of-Way								
311.00 Structures and Improvements	21.84		2.00%		19.00		65.81%	1.80%
312.00 Boiler Plant Equipment	21.84		2.15%		19.01		54.45%	2.40%
314.00 Turbogenerator Units	21.83		1.53%		19.00		58.78%	2.17%
315.00 Accessory Electric Equipment	21.83		1.86%		18.99		68.96%	1.63%
316.00 Miscellaneous Power Plant Equipment	21.83		0.10%		18.99		73.30%	1.41%
317.00 Asset Retirement Cost	21.82		1.34%		18.99		75.59%	1.29%
Total Navajo Unit 3			1.88%		19.01		57.99%	2.21%
Navajo Common								
310.00 Rights-of-Way	21.82		0.40%		18.99		77.78%	1.17%
311.00 Structures and Improvements	21.86		3.06%		19.01		42.35%	3.03%
312.00 Boiler Plant Equipment	21.86		3.17%		19.01		38.61%	3.22%
314.00 Turbogenerator Units					19.02		19.42%	4.24%
315.00 Accessory Electric Equipment	21.86		3.26%		19.02		25.25%	3.93%
316.00 Miscellaneous Power Plant Equipment	21.86		3.14%		19.01		40.14%	3.15%
317.00 Asset Retirement Cost								
Total Navajo Common			3.11%		19.01		40.48%	3.13%
San Juan								
310.00 Rights-of-Way								
311.00 Structures and Improvements	29.84		0.82%		27.08		83.00%	0.62%
312.00 Boiler Plant Equipment	29.74		1.09%		26.99		68.78%	1.15%
314.00 Turbogenerator Units	29.79		1.13%		26.95		71.95%	1.05%
315.00 Accessory Electric Equipment	29.46		0.79%		26.70		82.22%	0.66%
316.00 Miscellaneous Power Plant Equipment	28.99		0.87%		26.27		81.57%	0.70%
317.00 Asset Retirement Cost	29.90		0.89%		27.13		90.92%	0.33%
Total San Juan			1.06%		26.96		71.41%	1.06%

TUCSON ELECTRIC POWER COMPANY Statement A

Comparison of Present and Proposed Accrual Rates

Present: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description	Present Rem. Life	Present Fut. Net Salvage	Present Accrual Rate	Proposed Avg. Life	Proposed Rem. Life	Proposed Net Salvage	Proposed Reserve Ratio	Proposed Accrual Rate
A	B	C	D	E	F	G	H	I
San Juan Unit 1								
310.00 Rights-of-Way								
311.00 Structures and Improvements	31.10		0.75%		28.34		81.53%	0.65%
312.00 Boiler Plant Equipment	31.12		1.00%		28.35		68.48%	1.11%
314.00 Turbogenerator Units	31.11		1.04%		28.35		73.37%	0.94%
315.00 Accessory Electric Equipment	31.10		0.87%		28.34		77.08%	0.81%
316.00 Miscellaneous Power Plant Equipment	31.10		0.75%		28.35		70.71%	1.03%
317.00 Asset Retirement Cost	31.08		0.97%		28.32		88.28%	0.41%
Total San Juan Unit 1			0.98%		28.35		70.99%	1.02%
San Juan Unit 2								
310.00 Rights-of-Way								
311.00 Structures and Improvements	28.34		0.90%		25.56		84.82%	0.59%
312.00 Boiler Plant Equipment	28.36		1.11%		25.58		70.86%	1.14%
314.00 Turbogenerator Units	28.36		1.23%		25.58		70.40%	1.16%
315.00 Accessory Electric Equipment	28.34		0.73%		25.56		85.72%	0.58%
316.00 Miscellaneous Power Plant Equipment	28.34		0.91%		25.56		85.01%	0.59%
317.00 Asset Retirement Cost	28.32		0.77%		25.54		94.43%	0.22%
Total San Juan Unit 2			1.09%		25.58		73.04%	1.06%
San Juan Common								
310.00 Rights-of-Way								
311.00 Structures and Improvements								
312.00 Boiler Plant Equipment	31.16		2.33%		28.39		38.37%	2.17%
314.00 Turbogenerator Units								
315.00 Accessory Electric Equipment								
316.00 Miscellaneous Power Plant Equipment								
317.00 Asset Retirement Cost								
Total San Juan Common			2.33%		28.39		38.37%	2.17%
Springerville								
310.00 Rights-of-Way	13.42		4.81%		10.51		56.67%	4.16%
311.00 Structures and Improvements	19.52		3.08%		16.14		47.41%	3.46%
312.00 Boiler Plant Equipment	35.22		2.38%		26.15		31.73%	2.79%
314.00 Turbogenerator Units	36.76		2.13%		29.43		34.25%	2.39%
315.00 Accessory Electric Equipment	39.69		1.73%		34.90		37.17%	1.85%
316.00 Miscellaneous Power Plant Equipment	37.58		2.32%		24.76		33.70%	2.85%
317.00 Asset Retirement Cost								
Total Springerville			2.39%		25.47		34.98%	2.73%
Springerville Unit 1								
310.00 Rights-of-Way								
311.00 Structures and Improvements	11.33		-1.24%		8.41		32.22%	8.06%
312.00 Boiler Plant Equipment	11.33		7.40%		8.41		19.30%	9.80%
314.00 Turbogenerator Units	11.33		6.97%		8.41		28.01%	8.80%
315.00 Accessory Electric Equipment	11.33		7.08%		8.41		17.11%	9.86%
316.00 Miscellaneous Power Plant Equipment	11.33		6.25%		8.41		21.48%	9.34%
317.00 Asset Retirement Cost								
Total Springerville Unit 1			7.15%		8.41		20.97%	9.40%

TUCSON ELECTRIC POWER COMPANY Statement A

Comparison of Present and Proposed Accrual Rates
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

	Present			Proposed				
Account Description	Rem. Life	Fut. Net Salvage	Accrual Rate	Avg. Life	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H	I
Springerville Unit 2								
310.00 Rights-of-Way								
311.00 Structures and Improvements	43.70		1.57%		41.03		36.73%	1.54%
312.00 Boiler Plant Equipment	43.71		1.49%		41.05		33.36%	1.62%
314.00 Turbogenerator Units	43.70		1.50%		41.04		35.18%	1.58%
315.00 Accessory Electric Equipment	43.70		1.50%		41.03		36.62%	1.54%
316.00 Miscellaneous Power Plant Equipment	43.70		1.51%		41.04		34.60%	1.59%
317.00 Asset Retirement Cost								
Total Springerville Unit 2			1.50%		41.04		34.29%	1.60%
Springerville Unit 1 Common								
310.00 Rights-of-Way	11.33		5.36%		8.41		59.16%	4.86%
311.00 Structures and Improvements	11.33		4.61%		8.41		55.70%	5.27%
312.00 Boiler Plant Equipment	11.33		6.91%		8.41		37.13%	7.48%
314.00 Turbogenerator Units	11.33		6.62%		8.41		40.75%	7.05%
315.00 Accessory Electric Equipment	11.33		6.99%		8.41		25.38%	8.87%
316.00 Miscellaneous Power Plant Equipment	11.33		5.26%		8.41		29.54%	8.38%
317.00 Asset Retirement Cost								
Total Springerville Unit 1 Common			5.06%		8.41		52.64%	5.63%
Springerville Unit 2 Common								
310.00 Rights-of-Way	16.15		4.24%		13.26		54.14%	3.46%
311.00 Structures and Improvements	16.15		3.41%		13.26		51.36%	3.67%
312.00 Boiler Plant Equipment	16.15		4.53%		13.27		42.13%	4.36%
314.00 Turbogenerator Units	16.15		4.49%		13.27		38.39%	4.64%
315.00 Accessory Electric Equipment	16.15		3.25%		13.26		53.20%	3.53%
316.00 Miscellaneous Power Plant Equipment	16.15		3.86%		13.27		40.27%	4.50%
317.00 Asset Retirement Cost								
Total Springerville Unit 2 Common			3.62%		13.26		50.05%	3.77%
Springerville Coal Handling								
310.00 Rights-of-Way								
311.00 Structures and Improvements								
312.00 Boiler Plant Equipment	11.33		4.69%		8.41		34.68%	7.77%
314.00 Turbogenerator Units								
315.00 Accessory Electric Equipment								
316.00 Miscellaneous Power Plant Equipment								
317.00 Asset Retirement Cost								
Total Springerville Coal Handling			4.69%		8.41		34.68%	7.77%

TUCSON ELECTRIC POWER COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/06 Plant Investment	2007 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
STEAM PRODUCTION				
310.00 Rights-of-Way	$4,603,469	$221,057	$191,346	($29,711)
311.00 Structures and Improvements	111,087,557	2,815,717	3,039,591	223,874
312.00 Boiler Plant Equipment	652,150,583	11,853,922	13,401,655	1,547,733
314.00 Turbogenerator Units	206,960,796	3,523,993	3,900,294	376,301
315.00 Accessory Electric Equipment	71,511,709	1,065,926	1,083,842	17,916
316.00 Miscellaneous Power Plant Equipment	19,281,167	337,309	376,520	39,211
317.00 Asset Retirement Cost	69,982	667	405	(262)
Total Steam Production Plant	$1,065,665,263	$19,818,591	$21,993,653	$2,175,062
TOTAL UTILITY	$1,065,665,263	$19,818,591	$21,993,653	$2,175,062
STEAM PRODUCTION (by Unit)				
Four Corners				
310.00 Rights-of-Way				
311.00 Structures and Improvements	1,691,269	15,874	9,033	(6,841)
312.00 Boiler Plant Equipment	66,217,489	481,770	514,556	32,786
314.00 Turbogenerator Units	9,486,313	70,718	105,319	34,601
315.00 Accessory Electric Equipment	1,049,881	5,179	1,378	(3,801)
316.00 Miscellaneous Power Plant Equipment	3,352,180	60,509	70,214	9,705
317.00 Asset Retirement Cost	15,554	72	(53)	(125)
Total Four Coners	$81,812,686	$634,122	$700,447	$66,325
Four Corners Unit 4				
310.00 Rights-of-Way				
311.00 Structures and Improvements	876,104	7,885	4,468	(3,417)
312.00 Boiler Plant Equipment	34,726,085	236,137	250,028	13,891
314.00 Turbogenerator Units	5,625,444	37,128	74,818	37,690
315.00 Accessory Electric Equipment	538,552	2,316	969	(1,347)
316.00 Miscellaneous Power Plant Equipment	1,697,131	30,718	34,961	4,243
317.00 Asset Retirement Cost	7,407	30	(38)	(68)
Total Four Corners Unit 4	$43,470,723	$314,214	$365,206	$50,992
Four Corners Unit 5				
310.00 Rights-of-Way				
311.00 Structures and Improvements	815,165	7,989	4,565	(3,424)
312.00 Boiler Plant Equipment	31,491,404	245,633	264,528	18,895
314.00 Turbogenerator Units	3,860,869	33,590	30,501	(3,089)
315.00 Accessory Electric Equipment	511,329	2,863	409	(2,454)
316.00 Miscellaneous Power Plant Equipment	1,655,049	29,791	35,253	5,462
317.00 Asset Retirement Cost	8,147	42	(15)	(57)
Total Four Corners Unit 5	$38,341,963	$319,908	$335,241	$15,333
Navajo				
310.00 Rights-of-Way	$12,229	$49	$143	$94
311.00 Structures and Improvements	$17,061,160	$403,952	$393,595	($10,357)
312.00 Boiler Plant Equipment	$81,964,899	$1,867,719	$1,991,429	$123,710
314.00 Turbogenerator Units	$18,825,320	$314,925	$412,064	$97,139
315.00 Accessory Electric Equipment	$9,708,735	$166,296	$158,673	($7,623)
316.00 Miscellaneous Power Plant Equipment	$3,499,563	$77,083	$83,632	$6,549
317.00 Asset Retirement Cost	$33,016	$405	$388	($17)
Total Navajo	$131,104,922	$2,830,429	$3,039,924	$209,495

TUCSON ELECTRIC POWER COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/06 Plant Investment	2007 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
Navajo Unit 1				
310.00 Rights-of-Way				
311.00 Structures and Improvements	3,215,311	51,445	42,121	(9,324)
312.00 Boiler Plant Equipment	25,495,011	573,638	637,375	63,737
314.00 Turbogenerator Units	6,327,101	101,866	137,298	35,432
315.00 Accessory Electric Equipment	2,276,860	29,144	24,818	(4,326)
316.00 Miscellaneous Power Plant Equipment	484,264	7,070	6,150	(920)
317.00 Asset Retirement Cost	9,975	111	100	(11)
Total Navajo Unit 1	$37,808,522	$763,274	$847,862	$84,588
Navajo Unit 2				
310.00 Rights-of-Way				
311.00 Structures and Improvements	1,754,012	22,101	31,046	8,945
312.00 Boiler Plant Equipment	25,161,828	566,141	558,593	(7,548)
314.00 Turbogenerator Units	6,322,311	118,859	140,355	21,496
315.00 Accessory Electric Equipment	2,555,079	40,881	45,225	4,344
316.00 Miscellaneous Power Plant Equipment	527,267	8,278	8,489	211
317.00 Asset Retirement Cost	10,972	132	132	
Total Navajo Unit 2	$36,331,469	$756,392	$783,840	$27,448
Navajo Unit 3				
310.00 Rights-of-Way				
311.00 Structures and Improvements	3,736,208	74,724	67,252	(7,472)
312.00 Boiler Plant Equipment	25,933,886	557,579	622,413	64,834
314.00 Turbogenerator Units	6,156,885	94,200	133,604	39,404
315.00 Accessory Electric Equipment	4,479,497	83,319	73,016	(10,303)
316.00 Miscellaneous Power Plant Equipment	539,126	539	7,602	7,063
317.00 Asset Retirement Cost	12,069	162	156	(6)
Total Navajo Unit 3	$40,857,671	$810,523	$904,043	$93,520
Navajo Common				
310.00 Rights-of-Way	$12,229	$49	$143	$94
311.00 Structures and Improvements	8,355,629	255,682	253,176	(2,506)
312.00 Boiler Plant Equipment	5,374,174	170,361	173,048	2,687
314.00 Turbogenerator Units	19,023		807	807
315.00 Accessory Electric Equipment	397,299	12,952	15,614	2,662
316.00 Miscellaneous Power Plant Equipment	1,948,906	61,196	61,391	195
317.00 Asset Retirement Cost				
Total Navajo Common	$16,107,260	$500,240	$504,179	$3,939
San Juan				
310.00 Rights-of-Way				
311.00 Structures and Improvements	19,641,908	160,429	122,427	(38,002)
312.00 Boiler Plant Equipment	192,931,275	2,102,935	2,226,567	123,632
314.00 Turbogenerator Units	66,352,523	750,422	693,601	(56,821)
315.00 Accessory Electric Equipment	16,759,984	131,841	110,809	(21,032)
316.00 Miscellaneous Power Plant Equipment	6,120,364	53,340	42,586	(10,754)
317.00 Asset Retirement Cost	21,412	190	70	(120)
Total San Juan	$301,827,466	$3,199,157	$3,196,060	($3,097)

TUCSON ELECTRIC POWER COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/06 Plant Investment	2007 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
San Juan Unit 1				
310.00 Rights-of-Way				
311.00 Structures and Improvements	10,898,556	81,739	70,841	(10,898)
312.00 Boiler Plant Equipment	95,024,476	950,245	1,054,772	104,527
314.00 Turbogenerator Units	34,585,905	359,693	325,108	(34,585)
315.00 Accessory Electric Equipment	6,780,954	58,994	54,926	(4,068)
316.00 Miscellaneous Power Plant Equipment	1,471,859	11,039	15,160	4,121
317.00 Asset Retirement Cost	12,226	119	50	(69)
Total San Juan Unit 1	$148,773,976	$1,461,829	$1,520,857	$59,028
San Juan Unit 2				
310.00 Rights-of-Way				
311.00 Structures and Improvements	8,743,352	78,690	51,586	(27,104)
312.00 Boiler Plant Equipment	92,503,107	1,026,784	1,054,535	27,751
314.00 Turbogenerator Units	31,766,618	390,729	368,493	(22,236)
315.00 Accessory Electric Equipment	9,979,030	72,847	55,883	(16,964)
316.00 Miscellaneous Power Plant Equipment	4,648,505	42,301	27,426	(14,875)
317.00 Asset Retirement Cost	9,186	71	20	(51)
Total San Juan Unit 2	$147,649,798	$1,611,422	$1,557,943	($53,479)
San Juan Common				
310.00 Rights-of-Way				
311.00 Structures and Improvements				
312.00 Boiler Plant Equipment	5,403,692	125,906	117,260	(8,646)
314.00 Turbogenerator Units				
315.00 Accessory Electric Equipment				
316.00 Miscellaneous Power Plant Equipment				
317.00 Asset Retirement Cost				
Total San Juan Common	$5,403,692	$125,906	$117,260	($8,646)
Springerville				
310.00 Rights-of-Way	$4,591,240	$221,008	$191,203	($29,805)
311.00 Structures and Improvements	72,693,220	2,235,462	2,514,536	279,074
312.00 Boiler Plant Equipment	311,036,920	7,401,498	8,669,103	1,267,605
314.00 Turbogenerator Units	112,296,640	2,387,928	2,689,310	301,382
315.00 Accessory Electric Equipment	43,993,109	762,610	812,982	50,372
316.00 Miscellaneous Power Plant Equipment	6,309,060	146,377	180,088	33,711
317.00 Asset Retirement Cost				
Total Springerville	$550,920,189	$13,154,883	$15,057,222	$1,902,339
Springerville Unit 1				
310.00 Rights-of-Way				
311.00 Structures and Improvements	861,114	(10,678)	69,406	80,084
312.00 Boiler Plant Equipment	40,245,601	2,978,174	3,863,578	885,404
314.00 Turbogenerator Units	11,950,982	832,983	1,051,686	218,703
315.00 Accessory Electric Equipment	842,972	59,682	83,117	23,435
316.00 Miscellaneous Power Plant Equipment	588,381	36,774	54,955	18,181
317.00 Asset Retirement Cost				
Total Springerville Unit 1	$54,489,050	$3,896,935	$5,122,742	$1,225,807

TUCSON ELECTRIC POWER COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/06 Plant Investment	2007 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
Springerville Unit 2				
310.00 Rights-of-Way				
311.00 Structures and Improvements	24,743,434	388,472	381,049	(7,423)
312.00 Boiler Plant Equipment	261,188,107	3,891,703	4,231,247	339,544
314.00 Turbogenerator Units	99,064,402	1,485,966	1,565,218	79,252
315.00 Accessory Electric Equipment	40,369,977	605,550	621,698	16,148
316.00 Miscellaneous Power Plant Equipment	4,882,984	73,733	77,639	3,906
317.00 Asset Retirement Cost				
Total Springerville Unit 2	$430,248,904	$6,445,424	$6,876,851	$431,427
Springerville Unit 1 Common				
310.00 Rights-of-Way	$2,310,402	$124,300	$112,286	($12,014)
311.00 Structures and Improvements	20,995,381	967,887	1,106,457	138,570
312.00 Boiler Plant Equipment	3,997,828	276,250	299,038	22,788
314.00 Turbogenerator Units	537,568	35,587	37,899	2,312
315.00 Accessory Electric Equipment	187,766	13,125	16,655	3,530
316.00 Miscellaneous Power Plant Equipment	252,514	13,282	21,161	7,879
317.00 Asset Retirement Cost				
Total Springerville Unit 1 Common	$28,281,459	$1,430,431	$1,593,496	$163,065
Springerville Unit 2 Common				
310.00 Rights-of-Way	$2,280,838	$96,708	$78,917	($17,791)
311.00 Structures and Improvements	26,093,291	889,781	957,624	67,843
312.00 Boiler Plant Equipment	4,700,824	212,947	204,956	(7,991)
314.00 Turbogenerator Units	743,688	33,392	34,507	1,115
315.00 Accessory Electric Equipment	2,592,394	84,253	91,512	7,259
316.00 Miscellaneous Power Plant Equipment	585,181	22,588	26,333	3,745
317.00 Asset Retirement Cost				
Total Springerville Unit 2 Common	$36,996,216	$1,339,669	$1,393,849	$54,180
Springerville Coal Handling				
310.00 Rights-of-Way				
311.00 Structures and Improvements				
312.00 Boiler Plant Equipment	904,560	42,424	70,284	27,860
314.00 Turbogenerator Units				
315.00 Accessory Electric Equipment				
316.00 Miscellaneous Power Plant Equipment				
317.00 Asset Retirement Cost				
Total Springerville Coal Handling	$904,560	$42,424	$70,284	$27,860

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

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	$4,603,469	$2,243,896	48.74%	$2,703,740	58.73%	$2,611,197	56.72%
311.00 Structures and Improvements	111,087,557	62,031,397	55.84%	50,418,266	45.39%	61,819,724	55.65%
312.00 Boiler Plant Equipment	652,150,583	332,664,743	51.01%	216,925,288	33.26%	329,513,882	50.53%
314.00 Turbogenerator Units	206,960,796	101,243,094	48.92%	69,417,734	33.54%	104,196,095	50.35%
315.00 Accessory Electric Equipment	71,511,709	38,182,016	53.39%	25,981,621	36.33%	37,843,337	52.92%
316.00 Miscellaneous Power Plant Equipment	19,281,167	10,338,786	53.62%	6,999,895	36.30%	10,714,071	55.57%
317.00 Asset Retirement Cost	69,982	56,347	80.52%	40,637	58.07%	61,973	88.56%
Total Steam Production Plant	$1,065,665,263	$546,760,278	51.31%	$372,487,181	34.95%	$546,760,278	51.31%
TOTAL UTILITY	$1,065,665,263	$546,760,278	51.31%	$372,487,181	34.95%	$546,760,278	51.31%
STEAM PRODUCTION (by Unit)							
Four Corners							
310.00 Rights-of-Way							
311.00 Structures and Improvements	1,691,269	1,326,997	78.46%	811,921	48.01%	1,477,521	87.36%
312.00 Boiler Plant Equipment	66,217,489	54,976,583	83.02%	29,643,166	44.77%	53,983,871	81.53%
314.00 Turbogenerator Units	9,486,313	6,453,998	68.03%	3,835,195	40.43%	6,991,685	73.70%
315.00 Accessory Electric Equipment	1,049,881	903,960	86.10%	559,964	53.34%	1,018,175	96.98%
316.00 Miscellaneous Power Plant Equipment	3,352,180	1,497,055	44.66%	926,014	27.62%	1,684,520	50.25%
317.00 Asset Retirement Cost	15,554	13,994	89.97%	9,256	59.51%	16,816	108.12%
Total Four Corners	$81,812,686	$65,172,587	79.66%	$35,785,516	43.74%	$65,172,587	79.66%
Four Corners Unit 4							
310.00 Rights-of-Way							
311.00 Structures and Improvements	876,104	686,109	78.31%	410,980	46.91%	769,631	87.85%
312.00 Boiler Plant Equipment	34,726,085	29,403,344	84.67%	15,375,780	44.28%	28,793,785	82.92%
314.00 Turbogenerator Units	5,625,444	3,457,471	61.46%	2,057,649	36.58%	3,853,301	68.50%
315.00 Accessory Electric Equipment	538,552	471,168	87.49%	275,605	51.18%	516,118	95.83%
316.00 Miscellaneous Power Plant Equipment	1,697,131	783,147	46.15%	462,901	27.28%	866,862	51.08%
317.00 Asset Retirement Cost	7,407	6,758	91.24%	4,433	59.85%	8,301	112.07%
Total Four Corners Unit 4	$43,470,723	$34,807,998	80.07%	$18,587,349	42.76%	$34,807,998	80.07%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

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
Four Corners Unit 5							
310.00 Rights-of-Way							
311.00 Structures and Improvements	815,165	640,888	78.62%	400,941	49.19%	707,890	86.84%
312.00 Boiler Plant Equipment	31,491,404	25,573,240	81.21%	14,267,386	45.31%	25,190,086	79.99%
314.00 Turbogenerator Units	3,860,869	2,996,527	77.61%	1,777,546	46.04%	3,138,384	81.29%
315.00 Accessory Electric Equipment	511,329	432,792	84.64%	284,359	55.61%	502,056	98.19%
316.00 Miscellaneous Power Plant Equipment	1,655,049	713,907	43.14%	463,112	27.98%	817,658	49.40%
317.00 Asset Retirement Cost	8,147	7,236	88.81%	4,823	59.20%	8,515	104.52%
Total Four Corners Unit 5	$38,341,963	$30,364,589	79.19%	$17,198,167	44.85%	$30,364,589	79.19%
Navajo							
310.00 Rights-of-Way	$12,229	$11,328	92.63%	$7,297	59.67%	$9,511	77.78%
311.00 Structures and Improvements	17,061,160	9,600,745	56.27%	7,452,639	43.68%	9,578,469	56.14%
312.00 Boiler Plant Equipment	81,964,899	44,523,169	54.32%	34,674,400	42.30%	44,152,726	53.87%
314.00 Turbogenerator Units	18,825,320	10,624,131	56.44%	8,644,306	45.92%	11,003,296	58.45%
315.00 Accessory Electric Equipment	9,708,735	6,563,222	67.60%	5,273,691	54.32%	6,691,639	68.92%
316.00 Miscellaneous Power Plant Equipment	3,499,563	2,024,017	57.84%	1,487,442	42.50%	1,910,916	54.60%
317.00 Asset Retirement Cost	33,016	25,633	77.64%	20,203	61.19%	25,689	77.81%
Total Navajo	$131,104,922	$73,372,246	55.96%	$57,559,980	43.90%	$73,372,246	55.96%
Navajo Unit 1							
310.00 Rights-of-Way							
311.00 Structures and Improvements	3,215,311	2,275,871	70.78%	1,848,732	57.50%	2,418,206	75.21%
312.00 Boiler Plant Equipment	25,495,011	13,705,332	53.76%	10,244,534	40.18%	13,400,211	52.56%
314.00 Turbogenerator Units	6,327,101	3,637,290	57.49%	2,844,814	44.96%	3,721,117	58.81%
315.00 Accessory Electric Equipment	2,276,860	1,742,143	76.52%	1,381,116	60.66%	1,806,548	79.34%
316.00 Miscellaneous Power Plant Equipment	484,264	353,348	72.97%	281,168	58.06%	367,778	75.95%
317.00 Asset Retirement Cost	9,975	7,966	79.86%	6,184	61.99%	8,089	81.09%
Total Navajo Unit 1	$37,808,522	$21,721,949	57.45%	$16,606,548	43.92%	$21,721,949	57.45%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

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 2							
310.00 Rights-of-Way							
311.00 Structures and Improvements	1,754,012	1,350,038	76.97%	922,104	52.57%	1,162,904	66.30%
312.00 Boiler Plant Equipment	25,161,828	14,479,408	57.55%	11,533,700	45.84%	14,545,633	57.81%
314.00 Turbogenerator Units	6,322,311	3,418,510	54.07%	2,901,926	45.90%	3,659,741	57.89%
315.00 Accessory Electric Equipment	2,555,079	1,808,197	70.77%	1,344,745	52.63%	1,695,914	66.37%
316.00 Miscellaneous Power Plant Equipment	527,267	373,600	70.86%	289,941	54.99%	365,656	69.35%
317.00 Asset Retirement Cost	10,972	8,571	78.12%	6,721	61.26%	8,476	77.25%
Total Navajo Unit 2	$36,331,469	$21,438,325	59.01%	$16,999,137	46.79%	$21,438,325	59.01%
Navajo Unit 3							
310.00 Rights-of-Way							
311.00 Structures and Improvements	3,736,208	2,357,702	63.10%	1,966,817	52.64%	2,458,746	65.81%
312.00 Boiler Plant Equipment	25,933,886	14,284,466	55.08%	11,296,025	43.56%	14,121,316	54.45%
314.00 Turbogenerator Units	6,156,885	3,566,339	57.92%	2,894,732	47.02%	3,618,744	58.78%
315.00 Accessory Electric Equipment	4,479,497	2,945,208	65.75%	2,470,863	55.16%	3,088,860	68.96%
316.00 Miscellaneous Power Plant Equipment	539,126	529,170	98.15%	316,124	58.64%	395,192	73.30%
317.00 Asset Retirement Cost	12,069	9,096	75.37%	7,298	60.47%	9,124	75.59%
Total Navajo Unit 3	$40,857,671	$23,691,981	57.99%	$18,951,859	46.39%	$23,691,981	57.99%
Navajo Common							
310.00 Rights-of-Way	$12,229	$11,328	92.63%	$7,297	59.67%	$9,511	77.78%
311.00 Structures and Improvements	8,355,629	3,617,134	43.29%	2,714,986	32.49%	3,538,613	42.35%
312.00 Boiler Plant Equipment	5,374,174	2,053,963	38.22%	1,600,142	29.77%	2,085,566	38.81%
314.00 Turbogenerator Units	19,023	1,992	10.47%	2,834	14.90%	3,694	19.42%
315.00 Accessory Electric Equipment	397,299	67,674	17.03%	76,967	19.37%	100,316	25.25%
316.00 Miscellaneous Power Plant Equipment	1,948,906	767,899	39.40%	600,209	30.80%	782,290	40.14%
317.00 Asset Retirement Cost							
Total Navajo Common	$16,107,260	$6,519,991	40.48%	$5,002,436	31.06%	$6,519,991	40.48%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

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
San Juan							
310.00 Rights-of-Way							
311.00 Structures and Improvements	19,641,908	15,643,238	79.64%	9,362,895	47.67%	16,302,174	83.00%
312.00 Boiler Plant Equipment	192,931,275	136,110,708	70.55%	76,180,745	39.49%	132,688,692	68.78%
314.00 Turbogenerator Units	66,352,523	45,812,497	69.04%	27,429,497	41.34%	47,739,583	71.95%
315.00 Accessory Electric Equipment	16,759,984	13,271,065	79.18%	7,953,633	47.46%	13,780,422	82.22%
316.00 Miscellaneous Power Plant Equipment	6,120,364	4,668,549	76.28%	2,896,061	47.32%	4,992,438	81.57%
317.00 Asset Retirement Cost	21,412	16,720	78.09%	11,178	52.20%	19,468	90.92%
Total San Juan	$301,827,466	$215,522,776	71.41%	$123,834,010	41.03%	$215,522,776	71.41%
San Juan Unit 1							
310.00 Rights-of-Way							
311.00 Structures and Improvements	10,898,556	8,679,482	79.64%	5,034,400	46.19%	8,885,977	81.53%
312.00 Boiler Plant Equipment	95,024,476	66,399,880	69.88%	36,865,065	38.80%	65,068,747	68.48%
314.00 Turbogenerator Units	34,585,905	24,355,868	70.42%	14,377,529	41.57%	25,377,082	73.37%
315.00 Accessory Electric Equipment	6,780,954	5,090,781	75.07%	2,961,192	43.67%	5,226,657	77.08%
316.00 Miscellaneous Power Plant Equipment	1,471,859	1,074,950	73.03%	589,677	40.06%	1,040,811	70.71%
317.00 Asset Retirement Cost	12,226	9,106	74.48%	6,115	50.02%	10,794	88.28%
Total San Juan Unit 1	$148,773,976	$105,610,067	70.99%	$59,833,979	40.22%	$105,610,067	70.99%
San Juan Unit 2							
310.00 Rights-of-Way							
311.00 Structures and Improvements	8,743,352	6,963,756	79.65%	4,328,495	49.51%	7,416,197	84.82%
312.00 Boiler Plant Equipment	92,503,107	67,637,690	73.12%	38,256,672	41.36%	65,546,807	70.86%
314.00 Turbogenerator Units	31,766,618	21,456,629	67.54%	13,051,968	41.09%	22,362,500	70.40%
315.00 Accessory Electric Equipment	9,979,030	8,180,284	81.97%	4,992,441	50.03%	8,553,765	85.72%
316.00 Miscellaneous Power Plant Equipment	4,648,505	3,593,600	77.31%	2,306,384	49.62%	3,951,628	85.01%
317.00 Asset Retirement Cost	9,186	7,614	82.88%	5,063	55.11%	8,674	94.43%
Total San Juan Unit 2	$147,649,798	$107,839,571	73.04%	$62,941,024	42.63%	$107,839,571	73.04%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

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
San Juan Common							
310.00 Rights-of-Way							
311.00 Structures and Improvements							
312.00 Boiler Plant Equipment	5,403,692	2,073,137	38.37%	1,059,007	19.60%	2,073,137	38.37%
314.00 Turbogenerator Units							
315.00 Accessory Electric Equipment							
316.00 Miscellaneous Power Plant Equipment							
317.00 Asset Retirement Cost							
Total San Juan Common	$5,403,692	$2,073,137	38.37%	$1,059,007	19.60%	$2,073,137	38.37%
Springerville							
310.00 Rights-of-Way	$4,591,240	$2,232,567	48.63%	$2,696,443	58.73%	$2,601,685	56.67%
311.00 Structures and Improvements	72,693,220	35,460,417	48.78%	32,790,811	45.11%	34,461,561	47.41%
312.00 Boiler Plant Equipment	311,036,920	97,054,282	31.20%	76,426,976	24.57%	98,688,593	31.73%
314.00 Turbogenerator Units	112,296,640	38,352,468	34.15%	29,508,735	26.28%	38,461,531	34.25%
315.00 Accessory Electric Equipment	43,993,109	17,443,769	39.65%	12,194,333	27.72%	16,353,102	37.17%
316.00 Miscellaneous Power Plant Equipment	6,309,060	2,149,165	34.06%	1,690,377	26.79%	2,126,197	33.70%
317.00 Asset Retirement Cost							
Total Springerville	$550,920,189	$192,692,669	34.98%	$155,307,675	28.19%	$192,692,669	34.98%
Springerville Unit 1							
310.00 Rights-of-Way							
311.00 Structures and Improvements	861,114	683,406	79.36%	364,749	42.36%	277,447	32.22%
312.00 Boiler Plant Equipment	40,245,601	7,213,196	17.92%	10,213,169	25.38%	7,768,683	19.30%
314.00 Turbogenerator Units	11,950,982	3,235,721	27.07%	4,086,525	34.19%	3,108,430	26.01%
315.00 Accessory Electric Equipment	842,972	165,506	19.63%	189,572	22.49%	144,198	17.11%
316.00 Miscellaneous Power Plant Equipment	588,381	127,330	21.64%	166,172	28.24%	126,400	21.48%
317.00 Asset Retirement Cost							
Total Springerville Unit 1	$54,489,050	$11,425,158	20.97%	$15,020,187	27.57%	$11,425,158	20.97%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

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
Springerville Unit 2							
310.00 Rights-of-Way							
311.00 Structures and Improvements	24,743,434	8,935,832	36.11%	6,493,873	26.24%	9,087,824	36.73%
312.00 Boiler Plant Equipment	261,188,107	86,535,343	33.13%	62,268,408	23.84%	87,141,271	33.36%
314.00 Turbogenerator Units	99,064,402	34,585,543	34.91%	24,901,632	25.14%	34,848,488	35.18%
315.00 Accessory Electric Equipment	40,369,977	15,752,197	39.02%	10,562,884	26.17%	14,782,185	36.62%
316.00 Miscellaneous Power Plant Equipment	4,882,984	1,740,420	35.64%	1,207,312	24.72%	1,689,567	34.60%
317.00 Asset Retirement Cost							
Total Springerville Unit 2	$430,248,904	$147,549,335	34.29%	$105,434,108	24.51%	$147,549,335	34.29%
Springerville Unit 1 Common							
310.00 Rights-of-Way	$2,310,402	$1,238,521	53.61%	$1,450,646	62.79%	$1,366,847	59.16%
311.00 Structures and Improvements	20,995,381	12,077,285	57.52%	12,411,465	59.12%	11,694,491	55.70%
312.00 Boiler Plant Equipment	3,997,828	1,226,592	30.68%	1,575,513	39.41%	1,484,500	37.13%
314.00 Turbogenerator Units	537,568	231,279	43.02%	232,511	43.25%	219,079	40.75%
315.00 Accessory Electric Equipment	187,766	46,997	25.03%	50,571	26.93%	47,650	25.38%
316.00 Miscellaneous Power Plant Equipment	252,514	66,475	26.33%	79,155	31.35%	74,583	29.54%
317.00 Asset Retirement Cost							
Total Springerville Unit 1 Common	$28,281,459	$14,887,150	52.64%	$15,799,861	55.87%	$14,887,150	52.64%
Springerville Unit 2 Common							
310.00 Rights-of-Way	$2,280,838	$994,046	43.58%	$1,245,797	54.62%	$1,234,839	54.14%
311.00 Structures and Improvements	26,093,291	13,763,894	52.75%	13,520,724	51.82%	13,401,799	51.36%
312.00 Boiler Plant Equipment	4,700,824	1,765,492	37.56%	1,998,054	42.50%	1,980,479	42.13%
314.00 Turbogenerator Units	743,688	299,925	40.33%	288,068	38.73%	285,534	38.39%
315.00 Accessory Electric Equipment	2,592,394	1,479,069	57.05%	1,391,306	53.67%	1,379,068	53.20%
316.00 Miscellaneous Power Plant Equipment	585,181	214,940	36.73%	237,738	40.63%	235,647	40.27%
317.00 Asset Retirement Cost							
Total Springerville Unit 2 Common	$36,996,216	$18,517,365	50.05%	$18,681,686	50.50%	$18,517,365	50.05%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Springerville Coal Handling							
310.00 Rights-of-Way							
311.00 Structures and Improvements							
312.00 Boiler Plant Equipment	904,560	313,659	34.68%	371,832	41.11%	313,659	34.68%
314.00 Turbogenerator Units							
315.00 Accessory Electric Equipment							
316.00 Miscellaneous Power Plant Equipment							
317.00 Asset Retirement Cost							
Total Springerville Coal Handling	$904,560	$313,659	34.68%	$371,832	41.11%	$313,659	34.68%

TUCSON ELECTRIC POWER COMPANY

Statement E

Proposed Parameters

Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	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
STEAM PRODUCTION												
310.00 Rights-of-Way			39.92	17.39	-3.8	-3.4			25.50	10.52		
311.00 Structures and Improvements			33.92	16.73	-4.1	-3.8			32.72	17.87		
312.00 Boiler Plant Equipment			33.92	16.73	-4.1	-3.8			37.64	25.12		
314.00 Turbogenerator Units			34.67	16.33	-2.5	-4.5			41.13	27.34		
315.00 Accessory Electric Equipment			41.60	17.09	-3.7	-3.6			47.83	30.45		
316.00 Miscellaneous Power Plant Equipment			41.60	17.09	-3.7	-3.6			37.26	23.73		
317.00 Asset Retirement Cost			27.29	15.94	-2.1	-3.9			53.09	22.26		
Total Steam Production Plant									38.13	24.80		
TOTAL UTILITY									38.13	24.80		
STEAM PRODUCTION (by Unit)												
Four Corners												
310.00 Rights-of-Way												
311.00 Structures and Improvements			46.03	26.50					45.59	23.71		
312.00 Boiler Plant Equipment			43.41	26.51					42.93	23.71		
314.00 Turbogenerator Units			45.00	26.50					39.81	23.72		
315.00 Accessory Electric Equipment			53.14	26.47					50.76	23.68		
316.00 Miscellaneous Power Plant Equipment			36.98	26.53					32.79	23.73		
317.00 Asset Retirement Cost			58.19	26.47					58.45	23.67		
Total Four Coners									42.15	23.71		

TUCSON ELECTRIC POWER COMPANY

Statement E

Proposed Parameters

Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	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
Four Corners Unit 4												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2031	200-SC	45.61	26.50			2031	200-SC	44.66	23.71		
312.00 Boiler Plant Equipment	2031	200-SC	42.93	26.51			2031	200-SC	42.55	23.71		
314.00 Turbogenerator Units	2031	200-SC	44.55	26.50			2031	200-SC	37.40	23.72		
315.00 Accessory Electric Equipment	2031	200-SC	51.10	26.47			2031	200-SC	48.50	23.68		
316.00 Miscellaneous Power Plant Equipment	2031	200-SC	36.21	26.53			2031	200-SC	32.63	23.73		
317.00 Asset Retirement Cost	2031	200-SC	58.68	26.47			2031	200-SC	58.95	23.67		
Total Four Corners Unit 4									41.42	23.71		
Four Corners Unit 5												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2031	200-SC	46.48	26.50			2031	200-SC	46.64	23.70		
312.00 Boiler Plant Equipment	2031	200-SC	43.95	26.51			2031	200-SC	43.35	23.71		
314.00 Turbogenerator Units	2031	200-SC	45.53	26.50			2031	200-SC	43.94	23.71		
315.00 Accessory Electric Equipment	2031	200-SC	55.48	26.48			2031	200-SC	53.37	23.69		
316.00 Miscellaneous Power Plant Equipment	2031	200-SC	37.78	26.53			2031	200-SC	32.95	23.73		
317.00 Asset Retirement Cost	2031	200-SC	57.75	26.47			2031	200-SC	58.01	23.67		
Total Four Corners Unit 5									43.00	23.71		
Navajo												
310.00 Rights-of-Way			47.03	21.82					47.09	18.99		
311.00 Structures and Improvements			33.64	21.85					33.74	19.00		
312.00 Boiler Plant Equipment			34.31	21.84					32.94	19.01		
314.00 Turbogenerator Units			41.53	21.84					35.14	19.00		
315.00 Accessory Electric Equipment			42.23	21.83					41.58	18.99		
316.00 Miscellaneous Power Plant Equipment			33.60	21.85					33.05	19.00		
317.00 Asset Retirement Cost			48.77	21.82					48.92	18.98		
Total Navajo									33.88	19.01		

TUCSON ELECTRIC POWER COMPANY

Statement E

Proposed Parameters

Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	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 Unit 1												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2026	200-SC	44.41	21.83			2026	200-SC	44.68	18.99		
312.00 Boiler Plant Equipment	2026	200-SC	33.44	21.85			2026	200-SC	31.78	19.01		
314.00 Turbogenerator Units	2026	200-SC	40.63	21.84			2026	200-SC	34.54	19.01		
315.00 Accessory Electric Equipment	2026	200-SC	48.32	21.82			2026	200-SC	48.27	18.99		
316.00 Miscellaneous Power Plant Equipment	2026	200-SC	45.44	21.82			2026	200-SC	45.28	18.99		
317.00 Asset Retirement Cost	2026	200-SC	49.71	21.82			2026	200-SC	49.94	18.98		
Total Navajo Unit 1									33.90	19.01		
Navajo Unit 2												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2026	200-SC	39.91	21.84			2026	200-SC	40.06	19.00		
312.00 Boiler Plant Equipment	2026	200-SC	35.54	21.84			2026	200-SC	35.08	19.00		
314.00 Turbogenerator Units	2026	200-SC	40.94	21.84			2026	200-SC	35.12	19.00		
315.00 Accessory Electric Equipment	2026	200-SC	39.96	21.84			2026	200-SC	40.11	19.00		
316.00 Miscellaneous Power Plant Equipment	2026	200-SC	42.30	21.83			2026	200-SC	42.19	18.99		
317.00 Asset Retirement Cost	2026	200-SC	48.76	21.82			2026	200-SC	48.99	18.98		
Total Navajo Unit 2									35.71	19.00		
Navajo Unit 3												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2026	200-SC	39.98	21.84			2026	200-SC	40.12	19.00		
312.00 Boiler Plant Equipment	2026	200-SC	35.64	21.84			2026	200-SC	33.68	19.01		
314.00 Turbogenerator Units	2026	200-SC	43.16	21.83			2026	200-SC	35.86	19.00		
315.00 Accessory Electric Equipment	2026	200-SC	42.18	21.83			2026	200-SC	42.35	18.99		
316.00 Miscellaneous Power Plant Equipment	2026	200-SC	45.08	21.83			2026	200-SC	45.91	18.99		
317.00 Asset Retirement Cost	2026	200-SC	47.82	21.82			2026	200-SC	48.04	18.99		
Total Navajo Unit 3									35.45	19.01		

TUCSON ELECTRIC POWER COMPANY

Statement E

Proposed Parameters

Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	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 Common												
310.00 Rights-of-Way	2026	200-SC	46.88	21.82			2026	200-SC	47.09	18.99		
311.00 Structures and Improvements	2026	200-SC	28.12	21.86			2026	200-SC	28.16	19.01		
312.00 Boiler Plant Equipment	2026	200-SC	27.76	21.86			2026	200-SC	27.07	19.01		
314.00 Turbogenerator Units							2026	200-SC	22.35	19.02		
315.00 Accessory Electric Equipment	2026	200-SC	27.37	21.86			2026	200-SC	23.59	19.02		
316.00 Miscellaneous Power Plant Equipment	2026	200-SC	27.99	21.86			2026	200-SC	27.47	19.01		
317.00 Asset Retirement Cost												
Total Navajo Common									27.57	19.01		
San Juan												
310.00 Rights-of-Way												
311.00 Structures and Improvements			51.86	29.84					51.74	27.08		
312.00 Boiler Plant Equipment			45.79	29.74					44.61	26.99		
314.00 Turbogenerator Units			47.37	29.79					45.94	26.95		
315.00 Accessory Electric Equipment			51.49	29.46					50.81	26.70		
316.00 Miscellaneous Power Plant Equipment			51.58	28.99					49.86	26.27		
317.00 Asset Retirement Cost			56.54	29.90					56.76	27.13		
Total San Juan									45.72	26.96		
San Juan Unit 1												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2036	200-SC	52.87	31.10			2036	200-SC	52.67	28.34		
312.00 Boiler Plant Equipment	2036	200-SC	47.97	31.12			2036	200-SC	46.32	28.35		
314.00 Turbogenerator Units	2036	200-SC	49.20	31.11			2036	200-SC	48.52	28.35		
315.00 Accessory Electric Equipment	2036	200-SC	51.07	31.10			2036	200-SC	50.31	28.34		
316.00 Miscellaneous Power Plant Equipment	2036	200-SC	50.31	31.10			2036	200-SC	47.30	28.35		
317.00 Asset Retirement Cost	2036	200-SC	56.45	31.08			2036	200-SC	56.66	28.32		
Total San Juan Unit 1									47.42	28.35		

TUCSON ELECTRIC POWER COMPANY

Statement E

Proposed Parameters

Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	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
San Juan Unit 2												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2033	200-SC	50.66	28.34			2033	200-SC	50.62	25.56		
312.00 Boiler Plant Equipment	2033	200-SC	44.55	28.36			2033	200-SC	43.62	25.58		
314.00 Turbogenerator Units	2033	200-SC	45.39	28.36			2033	200-SC	43.42	25.58		
315.00 Accessory Electric Equipment	2033	200-SC	51.77	28.34			2033	200-SC	51.15	25.56		
316.00 Miscellaneous Power Plant Equipment	2033	200-SC	51.97	28.34			2033	200-SC	50.73	25.56		
317.00 Asset Retirement Cost	2033	200-SC	56.66	28.32			2033	200-SC	56.90	25.54		
Total San Juan Unit 2									44.58	25.58		
San Juan Common												
310.00 Rights-of-Way												
311.00 Structures and Improvements												
312.00 Boiler Plant Equipment	2036	200-SC	35.40	31.16			2036	200-SC	35.31	28.39		
314.00 Turbogenerator Units												
315.00 Accessory Electric Equipment												
316.00 Miscellaneous Power Plant Equipment												
317.00 Asset Retirement Cost												
Total San Juan Common									35.31	28.39		
Springerville												
310.00 Rights-of-Way			25.36	13.42					25.47	10.51		
311.00 Structures and Improvements			30.97	19.52					29.40	16.14		
312.00 Boiler Plant Equipment			44.79	35.22					34.67	26.15		
314.00 Turbogenerator Units			47.30	36.76					39.92	29.43		
315.00 Accessory Electric Equipment			51.35	39.69					48.29	34.90		
316.00 Miscellaneous Power Plant Equipment			49.17	37.58					33.82	24.76		
317.00 Asset Retirement Cost												
Total Springerville									35.46	25.47		

TUCSON ELECTRIC POWER COMPANY

Statement E

Proposed Parameters

Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	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 1												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2015	200-SC	17.22	11.33			2015	200-SC	14.59	8.41		
312.00 Boiler Plant Equipment	2015	200-SC	15.05	11.33			2015	200-SC	11.27	8.41		
314.00 Turbogenerator Units	2015	200-SC	17.04	11.33			2015	200-SC	12.78	8.41		
315.00 Accessory Electric Equipment	2015	200-SC	14.10	11.33			2015	200-SC	10.85	8.41		
316.00 Miscellaneous Power Plant Equipment	2015	200-SC	17.72	11.33			2015	200-SC	11.72	8.41		
317.00 Asset Retirement Cost												
Total Springerville Unit 1									11.61	8.41		
Springerville Unit 2												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2050	200-SC	55.63	43.70			2050	200-SC	55.63	41.03		
312.00 Boiler Plant Equipment	2050	200-SC	55.14	43.71			2050	200-SC	53.90	41.05		
314.00 Turbogenerator Units	2050	200-SC	55.61	43.70			2050	200-SC	54.82	41.04		
315.00 Accessory Electric Equipment	2050	200-SC	55.60	43.70			2050	200-SC	55.57	41.03		
316.00 Miscellaneous Power Plant Equipment	2050	200-SC	55.58	43.70			2050	200-SC	54.52	41.04		
317.00 Asset Retirement Cost												
Total Springerville Unit 2									54.37	41.04		
Springerville Unit 1 Common												
310.00 Rights-of-Way	2015	200-SC	22.50	11.33			2015	200-SC	22.60	8.41		
311.00 Structures and Improvements	2015	200-SC	21.88	11.33			2015	200-SC	20.57	8.41		
312.00 Boiler Plant Equipment	2015	200-SC	16.86	11.33			2015	200-SC	13.88	8.41		
314.00 Turbogenerator Units	2015	200-SC	15.06	11.33			2015	200-SC	14.82	8.41		
315.00 Accessory Electric Equipment	2015	200-SC	13.92	11.33			2015	200-SC	11.51	8.41		
316.00 Miscellaneous Power Plant Equipment	2015	200-SC	19.76	11.33			2015	200-SC	12.25	8.41		
317.00 Asset Retirement Cost												
Total Springerville Unit 1 Common									19.06	8.41		

TUCSON ELECTRIC POWER COMPANY

Statement E

Proposed Parameters

Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	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												
310.00 Rights-of-Way	2020	200-SC	29.10	16.15			2020	200-SC	29.22	13.26		
311.00 Structures and Improvements	2020	200-SC	28.53	16.15			2020	200-SC	27.52	13.26		
312.00 Boiler Plant Equipment	2020	200-SC	24.08	16.15			2020	200-SC	23.08	13.27		
314.00 Turbogenerator Units	2020	200-SC	21.82	16.15			2020	200-SC	21.66	13.27		
315.00 Accessory Electric Equipment	2020	200-SC	28.62	16.15			2020	200-SC	28.62	13.26		
316.00 Miscellaneous Power Plant Equipment	2020	200-SC	28.12	16.15			2020	200-SC	22.35	13.27		
317.00 Asset Retirement Cost												
Total Springerville Unit 2 Common									26.79	13.26		
Springerville Coal Handling												
310.00 Rights-of-Way												
311.00 Structures and Improvements												
312.00 Boiler Plant Equipment	2015	200-SC	23.90	11.33			2015	200-SC	14.28	8.41		
314.00 Turbogenerator Units												
315.00 Accessory Electric Equipment												
316.00 Miscellaneous Power Plant Equipment												
317.00 Asset Retirement Cost												
Total Springerville Coal Handling									14.28	8.41		

Statements A through E

Distribution and General

TUCSON ELECTRIC POWER COMPANY Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	Present Rem. Life	Present Fut. Net Salvage	Present Accrual Rate	Proposed Avg. Life	Proposed Rem. Life	Proposed Net Salvage	Proposed Reserve Ratio	Proposed Accrual Rate
A	B	C	D	E	F	G	H	I
DISTRIBUTION PLANT								
360.00 Rights-of-Way			2.22%		43.78		37.61%	1.43%
361.00 Structures and Improvements		-10.0%	2.44%		44.83		26.99%	1.63%
362.00 Station Equipment		-19.0%	4.25%		46.02		33.01%	1.46%
364.00 Poles, Towers and Fixtures		-59.0%	5.48%		39.16		35.98%	1.63%
365.00 Overhead Conductors and Devices		-17.0%	3.66%		41.83		38.71%	1.47%
366.00 Underground Conduit		-40.0%	2.33%		43.44		38.11%	1.42%
367.00 Underground Conductors and Devices		33.0%	1.63%		32.32		38.89%	1.89%
368.OH Line Transformers - Overhead		-15.0%	3.38%		26.12		51.83%	1.84%
368.UG Line Transformers - Underground		-15.0%	3.38%		23.28		41.39%	2.52%
369.OH Services - Overhead		-34.0%	3.83%		28.70		53.55%	1.62%
369.UG Services - Underground		-34.0%	3.83%		47.81		28.30%	1.50%
370.00 Meters		-25.0%	3.79%		19.73		40.91%	2.99%
373.00 Street Lighting and Signal Systems		-25.0%	4.46%		36.67		36.24%	1.74%
374.00 Asset Retirement Costs		-7.0%	3.22%		31.53		6.20%	2.97%
Total Distribution Plant			3.35%		33.61		38.52%	1.82%
GENERAL PLANT								
Depreciable								
390.00 Structures and Improvements			2.22%		21.45		54.04%	2.14%
391.CM Office Furn. and Equip. - Computer			20.00%		2.95		57.04%	14.56%
392.C0 Transportation Equipment - Class 0		16.0%	8.87%		14.63	15.0%	25.99%	4.03%
392.C1 Transportation Equipment - Class 1		16.0%	14.00%		5.10	15.0%	41.06%	8.62%
392.C2 Transportation Equipment - Class 2		21.0%	11.29%		4.99	25.0%	36.55%	7.71%
392.C3 Transportation Equipment - Class 3		18.0%	10.25%		7.07	15.0%	41.05%	6.22%
392.C4 Transportation Equipment - Class 4		9.0%	7.00%		9.80	10.0%	43.96%	4.70%
392.C5 Transportation Equipment - Class 5		1.0%	7.07%		10.67	5.0%	38.28%	5.32%
396.00 Power Operated Equipment			3.33%		11.46	5.0%	46.95%	4.19%
397.00 Communication Equipment			6.67%		18.13		32.72%	3.71%
Total Depreciable			7.57%		9.53	4.0%	44.54%	5.31%
Amortizable								
391.FE Office Furn. and Equip. - Furniture	← 24 Year Amortization →				← 24 Year Amortization →			
393.00 Stores Equipment	← 15 Year Amortization →				← 15 Year Amortization →			
394.00 Tools, Shop and Garage Equipment	← 17 Year Amortization →				← 17 Year Amortization →			
395.00 Laboratory Equipment	← 17 Year Amortization →				← 17 Year Amortization →			
398.00 Miscellaneous Equipment	← 20 Year Amortization →				← 20 Year Amortization →			
Total Amortizable			8.00%		11.16		43.56%	5.06%
Total General Plant			7.65%		9.75	3.3%	44.37%	5.26%
TOTAL INVESTMENT			3.96%		25.53	0.5%	39.34%	2.30%
NET SALVAGE								
108.02 Distribution	43.08	-50.0%			33.61	-15.0%	5.68%	0.28%
Total Net Salvage					33.61		5.68%	0.28%
TOTAL UTILITY			3.96%		25.53	-6.7%	44.22%	2.54%

TUCSON ELECTRIC POWER COMPANY Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/06 Plant Investment	2007 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
DISTRIBUTION PLANT				
360.00 Rights-of-Way	$7,991,353	$177,408	$114,276	($63,132)
361.00 Structures and Improvements	6,282,094	153,283	102,398	(50,885)
362.00 Station Equipment	95,451,660	4,056,696	1,393,594	(2,663,102)
364.00 Poles, Towers and Fixtures	112,985,358	6,191,598	1,841,661	(4,349,937)
365.00 Overhead Conductors and Devices	106,758,542	3,907,363	1,569,351	(2,338,012)
366.00 Underground Conduit	49,342,484	1,149,680	700,663	(449,017)
367.00 Underground Conductors and Devices	213,374,544	3,478,005	4,032,779	554,774
368.OH Line Transformers - Overhead	77,837,532	2,630,909	1,432,211	(1,198,698)
368.UG Line Transformers - Underground	125,291,764	4,234,862	3,157,352	(1,077,510)
369.OH Services - Overhead	12,050,959	461,552	195,226	(266,326)
369.UG Services - Underground	79,968,804	3,062,805	1,199,532	(1,863,273)
370.00 Meters	32,881,789	1,246,220	983,165	(263,055)
373.00 Street Lighting and Signal Systems	9,334,415	416,315	162,419	(253,896)
374.00 Asset Retirement Costs	216,459	6,970	6,429	(541)
Total Distribution Plant	$929,767,757	$31,173,666	$16,891,056	($14,282,610)
GENERAL PLANT				
Depreciable				
390.00 Structures and Improvements	$33,154,910	$736,039	$709,515	($26,524)
391.CM Office Furn. and Equip. - Computer	14,945,262	2,989,052	2,176,030	(813,022)
392.C0 Transportation Equipment - Class 0	2,049,391	181,781	82,590	(99,191)
392.C1 Transportation Equipment - Class 1	5,484,650	767,851	472,777	(295,074)
392.C2 Transportation Equipment - Class 2	3,992,947	450,804	307,856	(142,948)
392.C3 Transportation Equipment - Class 3	6,524,182	668,729	405,804	(262,925)
392.C4 Transportation Equipment - Class 4	10,167,307	711,711	477,863	(233,848)
392.C5 Transportation Equipment - Class 5	8,742,410	618,088	465,096	(152,992)
396.00 Power Operated Equipment	9,674,675	322,167	405,369	83,202
397.00 Communication Equipment	29,835,899	1,990,054	1,106,912	(883,142)
Total Depreciable	$124,571,633	$9,436,276	$6,609,812	($2,826,464)
Amortizable				
391.FE Office Furn. and Equip. - Furniture	$11,185,402	$628,620	$466,431	($162,189)
393.00 Stores Equipment	988,421	102,203	65,829	(36,374)
394.00 Tools, Shop and Garage Equipment	6,144,619	646,414	361,304	(285,110)
395.00 Laboratory Equipment	4,273,433	523,068	251,278	(271,790)
398.00 Miscellaneous Equipment	4,582,190	273,557	229,110	(44,447)
Total Amortizable	$27,174,065	$2,173,862	$1,373,952	($799,910)
Total General Plant	$151,745,698	$11,610,138	$7,983,764	($3,626,374)
TOTAL INVESTMENT	$1,081,513,455	$42,783,804	$24,874,820	($17,908,984)
NET SALVAGE				
108.02 Distribution	$929,767,757		$2,603,350	$2,603,350
Total Net Salvage	$929,767,757		$2,603,350	$2,603,350
TOTAL UTILITY	$1,081,513,455	$42,783,804	$27,478,170	($15,305,634)

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

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
DISTRIBUTION PLANT							
360.00 Rights-of-Way	$7,991,353	$2,895,049	36.23%	$2,160,329	27.03%	$3,005,269	37.61%
361.00 Structures and Improvements	6,282,094	1,745,626	27.79%	1,218,695	19.40%	1,695,346	26.99%
362.00 Station Equipment	95,451,660	63,750,682	66.79%	22,652,764	23.73%	31,512,625	33.01%
364.00 Poles, Towers and Fixtures	112,985,358	80,761,513	71.48%	29,219,614	25.86%	40,647,876	35.98%
365.00 Overhead Conductors and Devices	106,758,542	59,379,565	55.62%	29,710,409	27.83%	41,330,629	38.71%
366.00 Underground Conduit	49,342,484	15,411,170	31.23%	13,517,020	27.39%	18,803,745	38.11%
367.00 Underground Conductors and Devices	213,374,544	46,664,347	21.87%	59,645,938	27.95%	82,974,427	38.89%
368.OH Line Transformers - Overhead	77,837,532	35,429,162	45.52%	28,999,763	37.26%	40,342,038	51.83%
368.UG Line Transformers - Underground	125,291,764	44,936,684	35.87%	37,277,513	29.75%	51,857,351	41.39%
369.OH Services - Overhead	12,050,959	4,425,290	36.72%	4,638,560	38.49%	6,452,776	53.55%
369.UG Services - Underground	79,968,804	38,184,810	47.75%	16,268,229	20.34%	22,630,996	28.30%
370.00 Meters	32,881,789	11,285,053	34.32%	9,670,422	29.41%	13,452,681	40.91%
373.00 Street Lighting and Signal Systems	9,334,415	5,835,404	62.51%	2,431,955	26.05%	3,383,132	36.24%
374.00 Asset Retirement Costs	216,459	183,359	84.71%	9,642	4.45%	13,414	6.20%
Total Distribution Plant	$929,767,757	$410,887,713	44.19%	$257,420,853	27.69%	$358,102,303	38.52%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$33,154,910	$10,501,396	31.67%	$13,488,079	40.68%	$17,918,337	54.04%
391.CM Office Furn. and Equip. - Computer	14,945,262	8,712,419	58.30%	6,417,501	42.94%	8,525,377	57.04%
392.C0 Transportation Equipment - Class 0	2,049,391	1,338,356	65.31%	400,989	19.57%	532,697	25.99%
392.C1 Transportation Equipment - Class 1	5,484,650	3,422,840	62.41%	1,695,255	30.91%	2,252,075	41.06%
392.C2 Transportation Equipment - Class 2	3,992,947	1,811,726	45.37%	1,098,436	27.51%	1,459,225	36.55%
392.C3 Transportation Equipment - Class 3	6,524,182	3,316,186	50.83%	2,016,061	30.90%	2,678,251	41.05%
392.C4 Transportation Equipment - Class 4	10,167,307	6,010,038	59.11%	3,364,841	33.09%	4,470,047	43.96%
392.C5 Transportation Equipment - Class 5	8,742,410	3,716,054	42.51%	2,519,397	28.82%	3,346,911	38.28%
396.00 Power Operated Equipment	9,674,675	1,688,481	17.45%	3,419,033	35.34%	4,542,040	46.95%
397.00 Communication Equipment	29,835,899	16,583,464	55.58%	7,348,012	24.63%	9,761,521	32.72%
Total Depreciable	$124,571,633	$57,100,960	45.84%	$41,767,604	33.53%	$55,486,481	44.54%

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Company Vintage Group Procedure
December 31, 2006

Account Description	Plant Investment	Recorded Reserve		Computed Reserve		Redistributed Reserve	
		Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Amortizable							
391.FE Office Furn. and Equip. - Furniture	$11,185,402	$4,027,836	36.01%	$4,086,701	36.54%	$4,086,701	36.54%
393.00 Stores Equipment	988,421	694,316	70.24%	542,469	54.88%	542,469	54.88%
394.00 Tools, Shop and Garage Equipment	6,144,619	2,906,862	47.31%	3,790,382	61.69%	3,790,382	61.69%
395.00 Laboratory Equipment	4,273,433	1,504,997	35.22%	2,084,343	48.77%	2,084,343	48.77%
398.00 Miscellaneous Equipment	4,582,190	1,089,678	23.78%	1,334,272	29.12%	1,334,272	29.12%
Total Amortizable	$27,174,065	$10,223,688	37.62%	$11,838,167	43.56%	$11,838,167	43.56%
Total General Plant	$151,745,698	$67,324,648	44.37%	$53,605,771	35.33%	$67,324,648	44.37%
TOTAL INVESTMENT	$1,081,513,455	$478,212,361	44.22%	$311,026,624	28.76%	$425,426,951	39.34%
NET SALVAGE							
108.02 Distribution	$929,767,757			$37,944,646	4.08%	$52,785,410	5.68%
Total Net Salvage	$929,767,757			$37,944,646	4.08%	$52,785,410	5.68%
TOTAL UTILITY	$1,081,513,455	$478,212,361	44.22%	$348,971,270	32.27%	$478,212,361	44.22%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average Rate
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
DISTRIBUTION PLANT									
360.00 Rights-of-Way	$7,991,353		$7,991,353						
361.00 Structures and Improvements	6,734,493	452,399	6,282,094						
362.00 Station Equipment	102,966,318	7,514,658	95,451,660						
364.00 Poles, Towers and Fixtures	118,724,296	5,738,938	112,965,358						
365.00 Overhead Conductors and Devices	113,057,203	6,298,661	106,758,542						
366.00 Underground Conduit	50,414,825	1,072,341	49,342,484						
367.00 Underground Conductors and Devices	218,642,197	5,267,653	213,374,544						
368.OH Line Transformers - Overhead	86,139,876	8,302,344	77,837,532						
368.UG Line Transformers - Underground	129,844,521	4,552,757	125,291,764						
369.OH Services - Overhead	13,678,550	1,627,591	12,050,959						
369.UG Services - Underground	80,056,171	87,367	79,968,804						
370.00 Meters	44,957,598	12,075,809	32,881,789						
373.00 Street Lighting and Signal Systems	10,126,293	791,878	9,334,415						
374.00 Asset Retirement Costs	216,459		216,459	-16.8%					
Total Distribution Plant	$983,550,153	$53,782,396	$929,767,757						
GENERAL PLANT									
Depreciable									
390.00 Structures and Improvements	$42,778,084	$9,623,174	$33,154,910	63.5%		$6,110,715		$6,110,715	14.3%
391.CM Office Furn. and Equip. - Computer	44,540,033	29,594,771	14,945,262						
392.C0 Transportation Equipment - Class 0	3,294,571	1,245,180	2,049,391	15.6%	15.0%	194,248	307,409	501,657	15.2%
392.C1 Transportation Equipment - Class 1	11,393,482	5,908,832	5,484,650	17.0%	15.0%	1,004,501	822,696	1,827,199	16.0%
392.C2 Transportation Equipment - Class 2	8,367,431	4,374,484	3,992,947	25.1%	25.0%	1,097,995	998,237	2,096,232	25.1%
392.C3 Transportation Equipment - Class 3	9,050,966	2,526,784	6,524,182	17.0%	15.0%	429,553	978,627	1,406,181	15.6%
392.C4 Transportation Equipment - Class 4	16,576,147	6,408,840	10,167,307	12.9%	10.0%	826,740	1,016,731	1,843,471	11.1%
392.C5 Transportation Equipment - Class 5	10,930,140	2,187,730	8,742,410	5.6%	5.0%	122,513	437,121	559,633	5.1%
396.00 Power Operated Equipment	12,886,160	3,211,485	9,674,675	6.0%	5.0%	192,689	483,734	676,423	5.2%
397.00 Communication Equipment	43,055,607	13,219,708	29,835,899	0.3%		39,659		39,659	0.1%
Total Depreciable	$202,872,621	$78,300,988	$124,571,633	12.8%	4.0%	$10,018,615	$5,044,555	$15,063,170	7.4%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement D

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
Amortizable									
391.FE Office Furn. and Equip. - Furniture	$14,084,885	$2,899,483	$11,185,402						
393.00 Stores Equipment	2,256,193	1,267,772	988,421						
394.00 Tools, Shop and Garage Equipment	9,193,006	3,048,387	6,144,619						
395.00 Laboratory Equipment	5,973,789	1,700,356	4,273,433						
398.00 Miscellaneous Equipment	5,037,290	455,100	4,582,190						
Total Amortizable	$36,545,163	$9,371,098	$27,174,065						
Total General Plant	$239,417,784	$87,672,086	$151,745,698	11.4%	3.3%	$10,018,615	$5,044,555	$15,063,170	6.3%
TOTAL INVESTMENT	$1,222,967,937	$141,454,482	$1,081,513,455	7.1%	0.5%	$10,018,615	$5,044,555	$15,063,170	1.2%
NET SALVAGE									
108.02 Distribution	$983,550,153	$53,782,396	$929,767,757	-16.8%	-15.0%	($9,035,443)	($139,465,164)	($148,500,606)	-15.1%
Total Net Salvage	$983,550,153	$53,782,396	$929,767,757	-16.8%	-15.0%	($9,035,443)	($139,465,164)	($148,500,606)	-15.1%
TOTAL UTILITY	$2,206,518,090	$195,236,878	$2,011,281,212	0.5%	-6.7%	$983,173	($134,420,608)	($133,437,436)	-6.0%

TUCSON ELECTRIC POWER COMPANY

Statement E

Proposed Parameters

Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	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
DISTRIBUTION PLANT												
360.00 Rights-of-Way	45.00	R2	45.00				60.00	R5	60.00	43.78		
361.00 Structures and Improvements	45.00	SQ	45.00			-10.0	55.00	R1	55.62	44.83		
362.00 Station Equipment	28.00	S5	28.00			-19.0	60.00	R1.5	60.34	46.02		
364.00 Poles, Towers and Fixtures	29.00	R1	29.00			-59.0	53.00	R3	52.82	39.16		
365.00 Overhead Conductors and Devices	32.00	R1.5	32.00			-17.0	58.00	R2.5	57.96	41.83		
366.00 Underground Conduit	60.00	R4	60.00			-40.0	60.00	R4	59.83	43.44		
367.00 Underground Conductors and Devices	41.00	R2.5	41.00			33.0	45.00	R4	44.86	32.32		
368.OH Line Transformers - Overhead	34.00	R2	34.00			-15.0	42.00	R4	41.63	26.12		
368.UG Line Transformers - Underground	34.00	R2	34.00			-15.0	33.00	R3	33.14	23.28		
369.OH Services - Overhead	35.00	R4	35.00			-34.0	47.00	S3	46.66	28.70		
369.UG Services - Underground	35.00	R4	35.00			-34.0	60.00	S3	60.02	47.81		
370.00 Meters	33.00	R3	33.00			-25.0	27.00	L1	27.95	19.73		
373.00 Street Lighting and Signal Systems	33.00	R3	33.00			-25.0	50.00	R2.5	49.59	36.67		
374.00 Asset Retirement Costs	24.00	R0.5	24.00			-7.0	33.00	R3	33.00	31.53		
Total Distribution Plant									46.48	33.61		
GENERAL PLANT												
Depreciable												
390.00 Structures and Improvements	45.00	SQ	45.00				30.00	R1	30.99	21.45	14.3	
391.CM Office Furn. and Equip. - Computer	5.00	SQ	5.00				5.00	S3	5.17	2.95		
392.C0 Transportation Equipment - Class 0	6.00	L3	6.00			16.0	18.00	O2	18.96	14.63	15.2	15.0
392.C1 Transportation Equipment - Class 1	6.00	L3	6.00			16.0	8.00	L2	7.92	5.10	16.0	15.0
392.C2 Transportation Equipment - Class 2	7.00	L3	7.00			21.0	8.00	L1.5	7.87	4.99	25.1	25.0
392.C3 Transportation Equipment - Class 3	8.00	L3	8.00			18.0	11.00	L2	11.03	7.07	15.6	15.0
392.C4 Transportation Equipment - Class 4	13.00	R4	13.00			9.0	15.00	L1.5	15.31	9.80	11.1	10.0
392.C5 Transportation Equipment - Class 5	14.00	R4	14.00			1.0	15.00	L2	15.30	10.67	5.1	5.0
396.00 Power Operated Equipment	30.00	SC	30.00				18.00	L2	18.21	11.46	5.2	5.0
397.00 Communication Equipment	15.00	S1	15.00				24.00	R3	24.03	18.13	0.1	
Total Depreciable									14.05	9.53	7.4	4.0

TUCSON ELECTRIC POWER COMPANY

Statement E

Proposed Parameters

Company Vintage Group Procedure

Account Description	Present Parameters						Proposed Parameters (at December 31, 2006)					
	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
Amortizable												
391.FE Office Furn. and Equip. - Furniture	24.00	L0	24.00			6.0	24.00	SQ	24.00	15.23		
393.00 Stores Equipment	15.00	S3	15.00				15.00	SQ	15.00	6.77		
394.00 Tools, Shop and Garage Equipment	17.00	S1	17.00				17.00	SQ	17.00	6.51		
395.00 Laboratory Equipment	17.00	S3	17.00				17.00	SQ	17.00	8.71		
398.00 Miscellaneous Equipment	20.00	R4	20.00				20.00	SQ	20.00	14.18		
Total Amortizable									19.78	11.16		
Total General Plant									14.82	9.75	6.3	3.3
TOTAL INVESTMENT									35.76	25.53	1.2	0.5
NET SALVAGE												
108.02 Distribution	60.00	R3	60.18	43.08	-52.5	-50.0			46.48	33.61	-15.1	-15.0
Total Net Salvage									46.48	33.61	-15.1	
TOTAL UTILITY									35.76	25.53	-6.0	-6.7

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the TEP depreciation 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 an example of the supporting schedules developed for Account 365.00 – Overhead Conductors and Devices and net salvage for the distribution function. 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 – Historical Net Salvage Analysis.

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. A weighted–average remaining–life is the sum of Column H divided by the sum of Column I. A 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 C) 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 5. 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 data 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 database 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. Ageing 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 average service 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 – HISTORICAL NET SALVAGE ANALYSIS

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 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

TUCSON ELECTRIC POWER COMPANY
Non-Generation
Distribution Plant
Account: 365.00 Overhead Conductors and Devices

Dispersion: 58 - R2.5
Procedure: Vintage Group

Generation Arrangement

Vintage	December 31, 2006 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
2006	0.5	3,859,140	58.00	57.53	0.9918	1.0000	3,629,317	63,088
2005	1.5	3,403,003	58.00	56.59	0.9756	1.0000	3,319,915	58,671
2004	2.5	3,654,533	56.00	55.65	0.9593	1.0000	3,505,965	63,006
2003	3.5	3,873,998	58.01	54.71	0.9432	1.0000	3,653,782	66,786
2002	4.5	4,039,890	58.01	53.78	0.9270	1.0000	3,744,984	69,641
2001	5.5	4,203,144	58.02	52.85	0.9109	1.0000	3,828,654	72,448
2000	6.5	1,332,512	58.02	51.92	0.8948	1.0000	1,192,396	22,965
1999	7.5	4,558,593	58.03	51.00	0.8788	1.0000	4,006,293	78,554
1998	8.5	3,014,326	58.04	50.08	0.8629	1.0000	2,601,120	51,935
1997	9.5	2,433,032	58.04	49.17	0.8473	1.0000	2,061,417	41,923
1996	10.5	1,755,096	57.82	48.26	0.8347	1.0000	1,464,943	30,353
1995	11.5	2,816,784	57.98	47.36	0.8168	1.0000	2,300,837	48,581
1994	12.5	2,166,971	57.66	46.46	0.8058	1.0000	1,746,057	37,580
1993	13.5	2,693,049	57.89	45.57	0.7872	1.0000	2,119,980	46,522
1992	14.5	2,804,234	58.25	44.68	0.7671	1.0000	2,151,143	48,144
1991	15.5	2,727,038	57.76	43.80	0.7583	1.0000	2,067,903	47,213
1990	16.5	2,520,968	57.10	42.92	0.7518	1.0000	1,895,206	44,154
1989	17.5	2,933,571	57.09	42.05	0.7367	1.0000	2,161,024	51,389
1988	18.5	2,644,577	57.34	41.19	0.7183	1.0000	1,899,498	46,119
1987	19.5	2,664,076	57.29	40.33	0.7039	1.0000	1,875,375	46,502
1986	20.5	3,300,661	57.43	39.48	0.6874	1.0000	2,268,899	57,475
1985	21.5	4,234,067	57.27	38.63	0.6745	1.0000	2,856,042	73,932
1984	22.5	2,638,748	57.44	37.79	0.6579	1.0000	1,736,080	45,938
1983	23.5	2,678,237	57.72	36.96	0.6403	1.0000	1,714,825	46,397
1982	24.5	3,243,337	58.19	36.13	0.6209	1.0000	2,013,897	55,733
1981	25.5	3,478,303	58.11	35.32	0.6078	1.0000	2,114,048	59,860
1980	26.5	2,799,175	58.10	34.51	0.5939	1.0000	1,662,334	48,175
1979	27.5	2,033,464	57.96	33.70	0.5814	1.0000	1,182,335	35,081
1978	28.5	2,405,343	58.09	32.91	0.5665	1.0000	1,362,591	41,407
1977	29.5	1,635,617	57.86	32.12	0.5551	1.0000	907,904	28,267
1976	30.5	1,291,135	58.42	31.34	0.5365	1.0000	692,643	22,101
1975	31.5	1,883,192	57.95	30.57	0.5275	1.0000	993,387	32,498
1974	32.5	2,135,616	58.31	29.80	0.5111	1.0000	1,091,591	36,625
1973	33.5	1,355,819	58.34	29.05	0.4979	1.0000	675,086	23,239
1972	34.5	824,948	57.50	28.30	0.4922	1.0000	406,077	14,347
1971	35.5	1,193,943	58.06	27.57	0.4748	1.0000	566,843	20,564
1970	36.5	659,508	52.07	26.84	0.5154	1.0000	339,927	12,667

TUCSON ELECTRIC POWER COMPANY
Non-Generation

Distribution Plant
Account: 365.00 Overhead Conductors and Devices

Dispersion: 58 - R2.5
Procedure: Vintage Group

Generation Arrangement

Vintage	December 31, 2006 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
1969	37.5	754,369	56.70	26.12	0.4606	1.0000	347,463	13,304
1968	38.5	524,188	57.65	25.41	0.4407	1.0000	231,004	9,092
1967	39.5	327,620	58.40	24.71	0.4231	1.0000	138,600	5,610
1966	40.5	620,181	59.67	24.02	0.4025	1.0000	249,595	10,393
1965	41.5	493,749	58.28	23.34	0.4004	1.0000	197,713	8,473
1964	42.5	643,751	59.05	22.67	0.3838	1.0000	247,087	10,902
1963	43.5	1,123,343	60.06	22.01	0.3664	1.0000	411,550	18,702
1962	44.5	858,430	58.93	21.36	0.3624	1.0000	311,135	14,568
1961	45.5	494,647	59.48	20.72	0.3484	1.0000	172,320	8,316
1960	46.5	336,629	58.84	20.10	0.3415	1.0000	114,974	5,721
1959	47.5	365,242	60.57	19.48	0.3216	1.0000	117,480	6,030
1958	48.5	707,582	61.22	18.88	0.3084	1.0000	218,245	11,558
1957	49.5	358,689	60.54	18.29	0.3022	1.0000	108,393	5,925
1956	50.5	350,853	61.16	17.72	0.2897	1.0000	101,653	5,737
1955	51.5	121,161	60.63	17.16	0.2830	1.0000	34,292	1,999
1954	52.5	175,389	62.21	16.61	0.2670	1.0000	46,836	2,819
1953	53.5	162,382	61.02	16.08	0.2635	1.0000	42,788	2,661
1952	54.5	100,639	61.48	15.56	0.2531	1.0000	25,472	1,637
1951	55.5	116,257	62.93	15.06	0.2393	1.0000	27,817	1,847
1950	56.5	90,461	63.48	14.57	0.2295	1.0000	20,761	1,425
1949	57.5	53,891	63.85	14.09	0.2207	1.0000	11,896	844
1948	58.5	176,153	64.98	13.64	0.2098	1.0000	36,963	2,711
1947	59.5	53,689	65.22	13.19	0.2023	1.0000	10,859	823
1946	60.5	19,881	65.66	12.76	0.1944	1.0000	3,865	303
1945	61.5	10,196	66.16	12.35	0.1867	1.0000	1,903	154
1944	62.5	2,349	66.90	11.95	0.1786	1.0000	420	35
1943	63.5	658	66.70	11.57	0.1734	1.0000	114	10
1942	64.5	5,044	67.28	11.20	0.1664	1.0000	839	75
1941	65.5	1,879	67.25	10.84	0.1612	1.0000	303	28
1940	66.5	7,314	68.85	10.50	0.1524	1.0000	1,115	106
1939	67.5	1,585	69.14	10.17	0.1470	1.0000	233	23
1938	68.5	2,306	70.69	9.85	0.1393	1.0000	321	33
1937	69.5	1,087	71.09	9.54	0.1342	1.0000	146	15
1936	70.5	266	71.22	9.24	0.1298	1.0000	35	4
1935	71.5	789	72.63	8.95	0.1233	1.0000	97	11
1934	72.5	533	73.87	8.68	0.1175	1.0000	63	7
1933	73.5	1,445	74.35	8.41	0.1131	1.0000	163	19

TUCSON ELECTRIC POWER COMPANY
Non-Generation
Distribution Plant
Account: 365.00 Overhead Conductors and Devices

Dispersion: 58 - R2.5
Procedure: Vintage Group

Generation Arrangement

Vintage	December 31, 2006 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
1932	74.5	917	75.47	8.14	0.1079	1.0000	99	12
1931	75.5	543	76.04	7.89	0.1037	1.0000	56	7
1930	76.5	2,142	76.46	7.64	0.0999	1.0000	214	28
1929	77.5	92	76.61	7.39	0.0964	1.0000	9	1
1928	78.5	130	78.88	7.15	0.0906	1.0000	12	2
1927	79.5	181	79.05	6.91	0.0874	1.0000	16	2
1926	80.5	264	80.88	6.67	0.0825	1.0000	22	3
Total	18.4	$106,758,542	57.96	41.83	0.7217	1.0000	$77,045,255	$1,841,855

TUCSON ELECTRIC POWER COMPANY
Non-Generation
Distribution Plant
Account: 365.00 Overhead Conductors and Devices

Age Distribution

Vintage	Age as of 12/31/2006	Derived Additions	1989 Opening Balance	Experience to 12/31/2006 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2006	0.5	3,659,140		3,659,140	1.0000	0.5000
2005	1.5	3,403,003		3,403,003	1.0000	1.5000
2004	2.5	3,654,533		3,654,533	1.0000	2.5000
2003	3.5	3,873,998		3,873,998	1.0000	3.5000
2002	4.5	4,039,890		4,039,890	1.0000	4.5000
2001	5.5	4,203,144		4,203,144	1.0000	5.5000
2000	6.5	1,332,512		1,332,512	1.0000	6.5000
1999	7.5	4,558,593		4,558,593	1.0000	7.5000
1998	8.5	3,014,702		3,014,326	0.9999	8.4989
1997	9.5	2,437,838		2,433,032	0.9980	9.4828
1996	10.5	1,801,427		1,755,096	0.9743	10.2562
1995	11.5	2,846,101		2,816,784	0.9897	11.3988
1994	12.5	2,314,981		2,166,971	0.9361	12.0634
1993	13.5	2,749,134		2,693,049	0.9796	13.2683
1992	14.5	2,792,290		2,804,234	1.0043	14.6051
1991	15.5	2,821,562		2,727,038	0.9665	15.0942
1990	16.5	2,788,470		2,520,968	0.9041	15.4018
1989	17.5	3,210,515		2,933,571	0.9137	16.3615
1988	18.5		2,829,164	2,644,577	0.9348	17.5860
1987	19.5		2,874,159	2,664,076	0.9269	18.4960
1986	20.5		3,549,531	3,300,661	0.9299	19.5952
1985	21.5		4,640,462	4,234,067	0.9124	20.3932
1984	22.5		2,843,864	2,638,748	0.9279	21.5172
1983	23.5		2,833,464	2,678,237	0.9452	22.7485
1982	24.5		3,331,939	3,243,337	0.9734	24.1627
1981	25.5		3,608,102	3,478,303	0.9640	25.0149
1980	26.5		2,923,712	2,799,175	0.9574	25.9464
1979	27.5		2,176,898	2,033,464	0.9341	26.7365
1978	28.5		2,535,747	2,405,343	0.9486	27.7856
1977	29.5		1,791,088	1,635,617	0.9132	28.4775
1976	30.5		1,343,967	1,291,135	0.9607	29.9453
1975	31.5		2,066,299	1,883,192	0.9114	30.3792
1974	32.5		2,275,346	2,135,616	0.9386	31.6390
1973	33.5		1,465,428	1,355,819	0.9252	32.5623
1972	34.5		974,919	824,948	0.8462	32.6017
1971	35.5		1,333,265	1,193,943	0.8955	34.0401
1970	36.5		1,214,600	659,508	0.5430	28.9125
1969	37.5		962,314	754,369	0.7839	34.4068

TUCSON ELECTRIC POWER COMPANY
Non-Generation
Distribution Plant
Account: 365.00 Overhead Conductors and Devices

Age Distribution

Vintage	Age as of 12/31/2006	Derived Additions	1989 Opening Balance	Experience to 12/31/2006 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1968	38.5		627,671	524,188	0.8351	36.2066
1967	39.5		371,545	327,620	0.8818	37.7922
1966	40.5		653,956	620,181	0.9484	39.8942
1965	41.5		580,545	493,749	0.8505	39.3146
1964	42.5		741,207	643,751	0.8685	40.8971
1963	43.5		1,248,805	1,123,343	0.8995	42.7052
1962	44.5		1,092,028	858,430	0.7861	42.3495
1961	45.5		636,719	494,647	0.7769	43.6721
1960	46.5		460,245	336,629	0.7314	43.7854
1959	47.5		426,821	365,242	0.8557	46.2606
1958	48.5		775,579	707,582	0.9123	47.6362
1957	49.5		432,812	358,689	0.8287	47.6684
1956	50.5		415,310	350,853	0.8448	48.9832
1955	51.5		158,595	121,161	0.7640	49.1287
1954	52.5		204,339	175,389	0.8583	51.3722
1953	53.5		222,812	162,382	0.7288	50.8285
1952	54.5		133,376	100,639	0.7546	51.9098
1951	55.5		139,964	116,257	0.8306	53.9648
1950	56.5		112,329	90,461	0.8053	55.0999
1949	57.5		74,953	53,891	0.7190	56.0370
1948	58.5		214,251	176,153	0.8222	57.7113
1947	59.5		99,906	53,689	0.5374	58.4760
1946	60.5		49,402	19,881	0.4024	59.4102
1945	61.5		21,546	10,196	0.4732	60.3929
1944	62.5		4,016	2,349	0.5849	61.5860
1943	63.5		1,430	658	0.4602	61.8165
1942	64.5		26,665	5,044	0.1892	62.8137
1941	65.5		5,965	1,879	0.3150	63.1698
1940	66.5		18,323	7,314	0.3992	65.1341
1939	67.5		7,905	1,585	0.2005	65.7631
1938	68.5		3,874	2,306	0.5952	67.6407
1937	69.5		2,590	1,087	0.4198	68.3395
1936	70.5		1,656	266	0.1609	68.7454
1935	71.5		2,312	789	0.3411	70.4100
1934	72.5		902	533	0.5910	71.8865
1933	73.5		3,106	1,445	0.4653	72.5935
1932	74.5		1,238	917	0.7402	73.9097
1931	75.5		1,145	543	0.4748	74.6631

TUCSON ELECTRIC POWER COMPANY

Non-Generation

Distribution Plant

Account: 365.00 Overhead Conductors and Devices

Age Distribution

Vintage	Age as of 12/31/2006	Derived Additions	1989 Opening Balance	Experience to 12/31/2006 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1930	76.5		4,039	2,142	0.5302	75.2456
1929	77.5		256	92	0.3583	75.5467
1928	78.5		205	130	0.6354	77.9531
1927	79.5		325	181	0.5581	78.2460
1926	80.5		335	264	0.7898	80.1847
1925	81.5		104		0.0000	75.1525
Total		$55,501,832	$57,555,371	$106,758,542	0.9443	

TUCSON ELECTRIC POWER COMPANY

Non-Generation

Distribution Plant

Account: 365.00 Overhead Conductors and Devices

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1989	57,669,804	3,245,148	733,541	709	60,182,120
1990	60,182,120	2,792,613	759,893	(244)	62,214,595
1991	62,214,595	2,792,300	676,038		64,330,857
1992	64,330,857	2,936,371	454,290	(7,792)	66,805,146
1993	66,805,146	2,632,723	474,822	(162,077)	68,800,971
1994	68,800,971	2,320,315	693,201	9,581	70,437,666
1995	70,437,666	2,840,766	489,569		72,788,863
1996	72,788,863	1,801,223	450,056		74,140,030
1997	74,140,030	2,415,541	564,517		75,991,055
1998	75,991,055	2,946,002	124,120		78,812,937
1999	78,812,937	722,259	9,369		79,525,827
2000	79,525,827	3,429,589			82,955,416
2001	82,955,416	4,692,270	18,925		87,628,761
2002	87,628,761	4,447,982	146,591		91,930,152
2003	91,930,152	3,693,806	356,847		95,267,112
2004	95,267,112	2,558,825		(99,520)	97,726,416
2005	97,726,416	3,102,173	176,340		100,652,249
2006	100,652,249	6,177,315	170,542	99,520	106,758,542

TUCSON ELECTRIC POWER COMPANY

Non-Generation

Distribution Plant

Account: 365.00 Overhead Conductors and Devices

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1989	57,561,573	3,212,049	733,541	709	60,040,789
1990	60,040,789	2,929,553	759,893	(244)	62,210,205
1991	62,210,205	2,828,638	676,038		64,362,805
1992	64,362,805	2,796,217	454,290	(7,792)	66,696,940
1993	66,696,940	2,749,134	474,822	(162,077)	68,809,175
1994	68,809,175	2,314,981	693,201	9,581	70,440,537
1995	70,440,537	2,846,101	489,569		72,797,069
1996	72,797,069	1,801,427	450,056		74,148,440
1997	74,148,440	2,437,838	564,517		76,021,761
1998	76,021,761	3,014,702	124,120		78,912,343
1999	78,912,343	4,558,593	9,369		83,461,568
2000	83,461,568	1,332,512			84,794,080
2001	84,794,080	4,203,144	18,925		88,978,299
2002	88,978,299	4,039,890	146,591		92,871,597
2003	92,871,597	3,873,998	356,847		96,388,749
2004	96,388,749	3,754,053		(99,520)	100,043,282
2005	100,043,282	3,403,003	176,340		103,269,944
2006	103,269,944	3,659,140	170,542		106,758,542

TUCSON ELECTRIC POWER COMPANY

Non-Generation

Distribution Plant

Account: 365.00 Overhead Conductors and Devices

T-Cut: None

Placement Band: 1925-2006

Hazard Function: Proportion Retired

Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	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
1989-1993	51.6	53.0	L0	8.20	109.3	O3 *	2.50	121.9	SC *	2.20
1990-1994	52.0	57.8	L0	6.11	63.8	O2	5.29	121.1	SC *	1.44
1991-1995	55.2	62.8	L0	5.72	74.5	O3 *	4.65	126.8	SC *	1.46
1992-1996	59.9	70.7	L0	5.65	95.1	O3 *	4.22	134.0	SC *	0.79
1993-1997	61.5	79.1	O2	4.42	104.7	O3 *	3.24	135.9	SC *	0.70
1994-1998	20.8	97.9	O2	5.29	86.6	L0	5.47	146.4	SC *	5.69
1995-1999	64.8	130.1	SC	2.01	94.9	R0.5	3.16	161.9	R1 *	2.30
1996-2000	76.9	155.5	R1	1.47	127.1	R1	1.87	173.2	R2 *	1.65
1997-2001	83.0	172.6	R2	1.28	134.7	R1.5	1.21	182.6	R4 *	1.72
1998-2002	86.8	151.0	R1.5 *	1.15	119.6	S1.5	2.40	183.1	R4 *	1.32
1999-2003	81.8	113.3	L1.5 *	2.96	81.6	S2	8.52	122.4	SC *	6.43
2000-2004	83.8	118.0	S0 *	3.07	85.5	S2	8.11	148.5	SC *	5.15
2001-2005	0.0	96.4	L1.5 *	26.32	67.3	S3 *	13.67	62.0	R4 *	6.23
2002-2006	1.2	86.9	L1.5 *	26.71	62.5	S3 *	12.52	59.1	S4 *	6.06

TUCSON ELECTRIC POWER COMPANY

Non-Generation

Distribution Plant

Account: 365.00 Overhead Conductors and Devices

T-Cut: None

Placement Band: 1925-2006

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	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
1989-2006	3.8	92.5	L0.5	22.79	65.6	R1.5	14.53	57.9	R2.5	6.52
1991-2006	3.8	96.5	L0.5	24.31	65.7	R2	14.15	58.8	R3	6.25
1993-2006	3.8	100.5	L1	25.68	66.7	R2	14.62	59.5	R3	5.95
1995-2006	3.7	103.9	L1	27.28	67.2	R2.5	14.57	60.7	R4	6.32
1997-2006	3.5	103.5	L1.5 *	28.20	67.8	S2 *	14.81	61.5	R4 *	6.40
1999-2006	2.9	99.9	L1.5 *	28.48	67.2	S3 *	14.55	61.6	S4 *	6.40
2001-2006	1.8	91.8	L1.5 *	27.57	64.4	S3 *	13.45	60.1	S4 *	6.33
2003-2006	0.6	85.2	L2 *	27.46	61.1	S3 *	12.56	58.1	S4 *	6.31
2005-2006	0.0	76.7	L2 *	26.32	56.3	S3 *	11.84	54.6	R5 *	7.48

TUCSON ELECTRIC POWER COMPANY

Non-Generation

Distribution Plant

Account: 365.00 Overhead Conductors and Devices

T-Cut: None

Placement Band: 1925-2006

Hazard Function: Proportion Retired

Weighting: Exposures

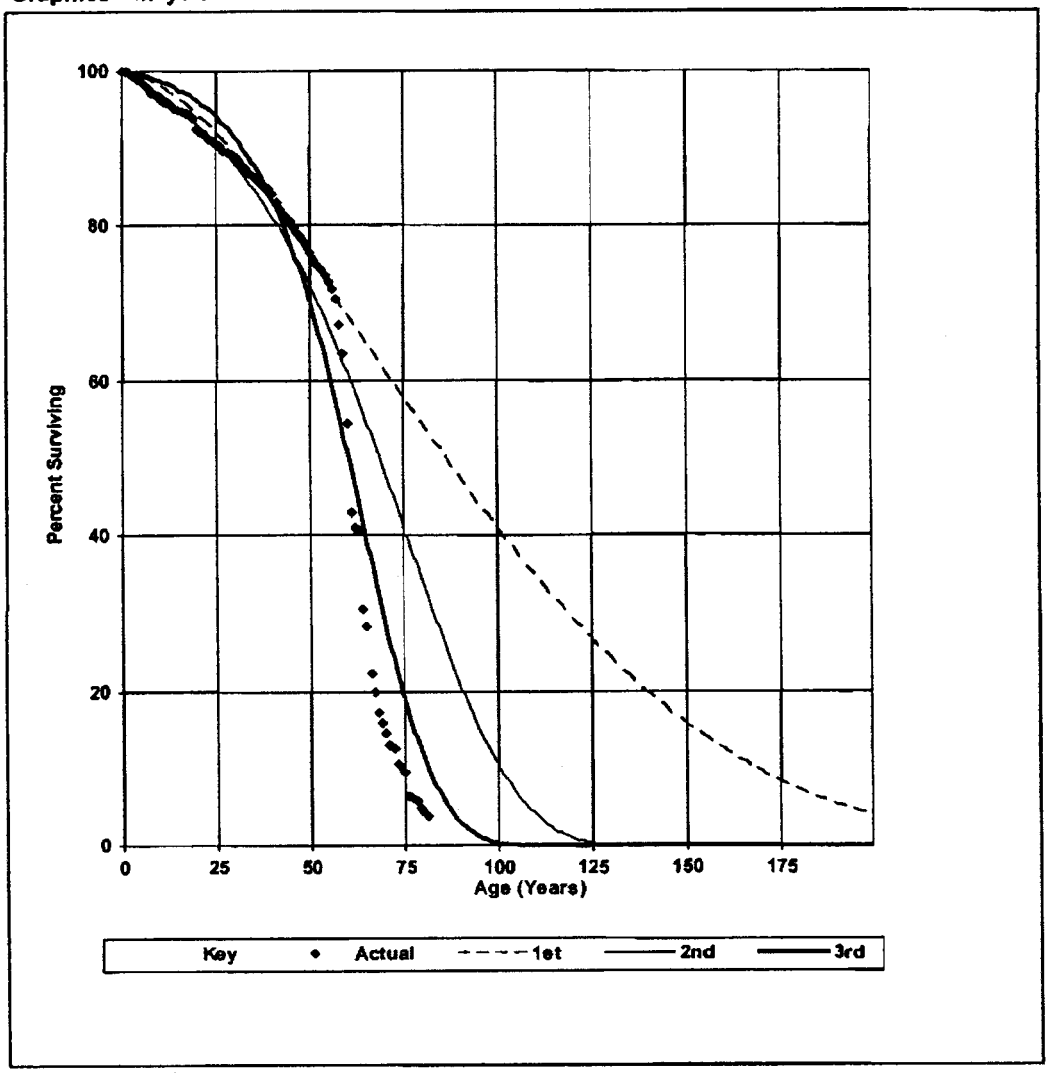
Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	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	47.0	45.1	L0	9.97	111.2	O4 *	4.10	112.5	O3 *	4.08
1989-1992	48.4	50.1	L0	8.21	98.3	O4 *	3.68	117.1	SC *	2.57
1989-1994	51.8	54.1	L0	7.99	109.2	O3 *	2.41	121.7	SC *	1.97
1989-1996	55.0	61.1	L0	7.37	114.1	O3 *	2.74	128.3	SC *	1.63
1989-1998	18.6	70.7	L0	6.98	122.9	SC *	4.91	136.0	SC *	5.36
1989-2000	62.7	86.9	O2	5.79	140.2	SC *	1.97	147.7	SC *	1.67
1989-2002	68.2	96.5	L0	5.08	142.5	SC *	2.22	152.8	SC *	1.39
1989-2004	71.3	99.1	L0	4.63	104.4	L0	4.25	150.8	SC *	0.60
1989-2006	3.8	92.5	L0.5	22.79	65.6	R1.5	14.53	57.9	R2.5	6.52

TUCSON ELECTRIC POWER COMPANY
Non-Generation
Distribution Plant
Account: 365.00 Overhead Conductors and Devices

T-Cut: None
Placement Band: 1925-2006 Observation Band: 1989-2006
Hazard Function: Proportion Retired
Weighting: Exposures
1st: 92.5-L0.5 2nd: 65.6-R1.5 3rd: 57.9-R2.5

Graphics Analysis

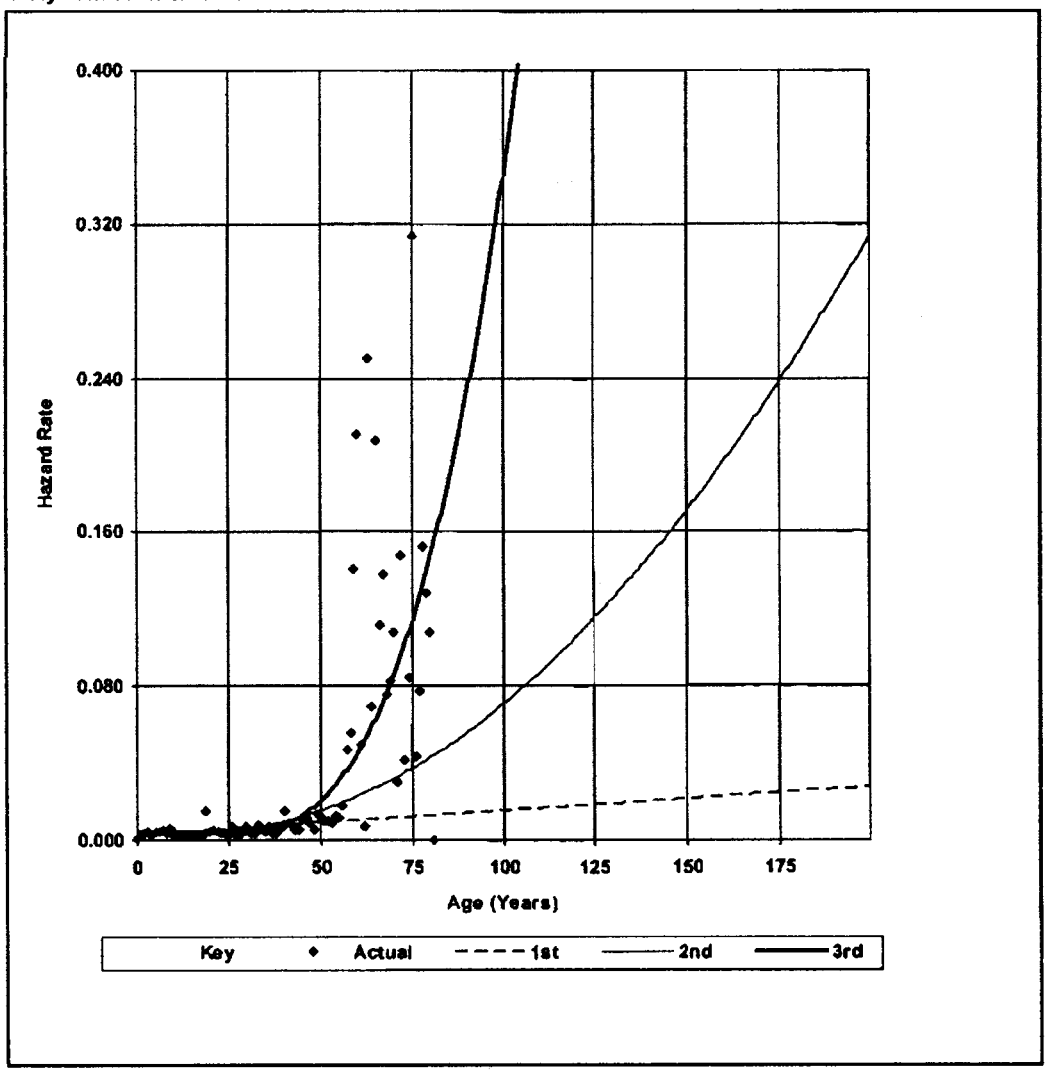


TUCSON ELECTRIC POWER COMPANY
Non-Generation
Distribution Plant
Account: 365.00 Overhead Conductors and Devices

T-Cut: None
Placement Band: 1925-2006 Observation Band: 1989-2006
Hazard Function: Proportion Retired
Weighting: Exposures

Polynomial Hazard Function

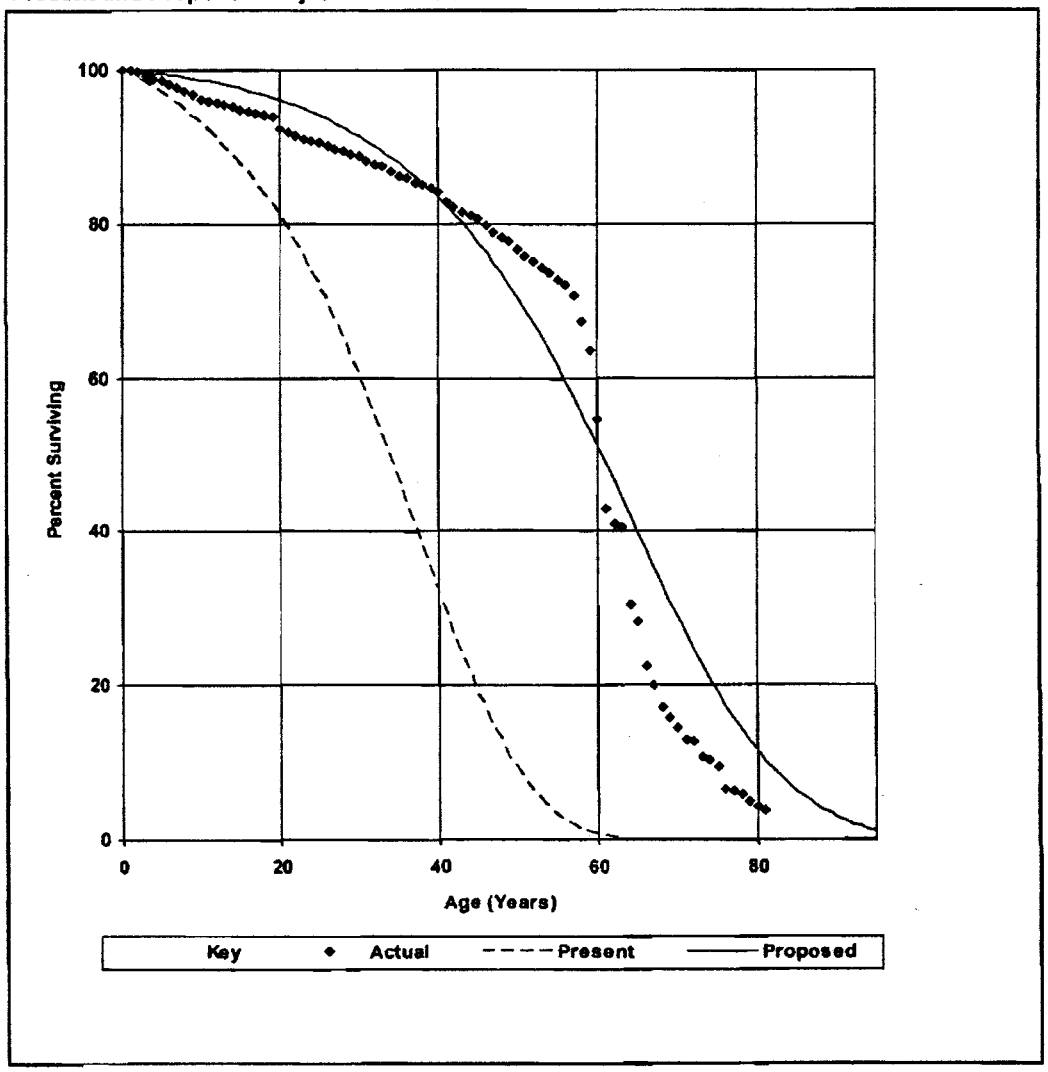
1st: 92.5-L0.5 2nd: 65.6-R1.5 3rd: 57.9-R2.5



TUCSON ELECTRIC POWER COMPANY
Non-Generation
Distribution Plant
Account: 365.00 Overhead Conductors and Devices

T-Cut: None
Placement Band: 1925-2006
Observation Band: 1989-2006

Present and Proposed Projection Life Curves **Present: 32.0-R1.5** **Proposed: 58.0-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	680,155	12.7		785,078	14.6		(104,923)	-2.0	
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	777,720	35.9	27.6	1,572,733	72.5	51.8	(795,013)	-36.7	-24.3
1994	3,641,728	973,976	26.7	32.4	2,389,843	65.6	67.7	(1,415,866)	-38.9	-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	992,788	43.1	32.7	1,291,111	56.1	62.9	(298,343)	-13.0	-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	-22.7
1999	90,038	166,727	185.2	35.7	311,919	346.4	53.4	(145,192)	-161.3	-17.7
2000	3,427,554	819,167	23.9	33.6	(6,212)	-0.2	39.8	825,379	24.1	-6.2
2001	87,700	67,789	77.3	31.1	266,993	304.4	37.9	(199,203)	-227.1	-6.7
2002	1,780,979	522,271	29.3	31.2	407,718	22.9	28.3	114,554	6.4	2.9
2003	1,284,928	514,230	40.0	31.3	209,557	16.3	17.8	304,673	23.7	13.5
2004	10,734,023		0.0	11.1		0.0	5.1		0.0	6.0
2005	3,344,454	2,323,660	69.5	19.9	846,755	25.3	10.0	1,476,905	44.2	9.8
2006	2,609,551	445,063	17.1	19.3	4,691,270	179.8	31.2	(4,246,207)	-162.7	-11.9
Total	53,782,395	13,837,213	25.7		22,885,109	42.6		(9,047,896)	-16.8	

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	5,361,910	680,155	12.7		785,078	14.6		(104,923)	-2.0	
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	777,720	35.9	27.6	1,572,733	72.5	51.8	(795,013)	-36.7	-24.3
1994	3,641,728	973,976	26.7	32.4	2,389,843	65.6	67.7	(1,415,866)	-38.9	-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	992,768	43.1	32.7	1,291,111	56.1	62.9	(298,343)	-13.0	-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	2,156,814	545,596	25.3	30.4	944,014	43.8	51.8	(398,419)	-18.5	-21.4
1999	975,061	166,727	17.1	30.4	311,919	32.0	45.5	(145,192)	-14.9	-15.1
2000	4,408,607	819,167	18.6	26.4	(6,212)	-0.1	31.2	825,379	18.7	-4.9
2001	1,245,580	67,789	5.4	20.5	266,993	21.4	25.0	(199,203)	-16.0	-4.4
2002	3,497,746	522,271	14.9	17.3	407,718	11.7	15.7	114,554	3.3	1.6
2003	4,503,501	514,230	11.4	14.3	209,557	4.7	8.1	304,673	8.8	6.2
2004	2,029,183		0.0	12.3		0.0	5.6		0.0	6.7
2005	3,344,454	2,323,660	69.5	23.4	846,755	25.3	11.8	1,476,905	44.2	11.6
2006	2,609,551	445,063	17.1	23.8	4,691,270	179.8	38.5	(4,246,207)	-162.7	-14.7
Total	53,782,395	13,837,213	25.7		22,885,109	42.6		(9,047,896)	-16.8	

Direct Testimony of Judah L. Rose

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
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 ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-01933A-07-____

Direct Testimony of

Judah L. Rose

on Behalf of

Tucson Electric Power Company

PUBLIC VERSION

July 2, 2007

TABLE OF CONTENTS

I. Introduction 1

II. Summary 4

III. Valuation Approach 6

IV. Valuation Assumptions 14

V. Valuation Results 19

VI. Wholesale Power Markets 25

Exhibits:

Exhibit JLR-1	Judah L. Rose Resume
Exhibit JLR-2	Natural Gas Price Forecast
Exhibit JLR-3	Forecast Minemouth PRB Coal Prices
Exhibit JLR-4	Firmly Planned and Recently Completed Plants in Arizona-New Mexico-Southern Nevada
Exhibit JLR-5	Unplanned Fossil and Nuclear Unit Power Plant Capital Costs
Exhibit JLR-6	Unplanned Renewable Unit Capital Costs
Exhibit JLR-7	Unplanned Power Plant Full Load Heat Rate
Exhibit JLR-8	Unplanned Power Plant Non-Fuel Variable O&M Costs
Exhibit JLR-9	Emission Allowance Price Forecasts
Exhibit JLR-10	WECC Peak and Energy Demand Forecast
Exhibit JLR-11	ICF IPM® WECC Model Regions
Exhibit JLR-12	TEP Plant Details
Exhibit JLR-13	Financing Assumptions used in ICF IPM® Analysis
Exhibit JLR-14	Summary of Valuation Results
Exhibit JLR-15	Results – Coal Plants
Exhibit JLR-16	Arizona Energy, Capacity, and Firm Power Prices
Exhibit JLR-17	NERC Arizona/New Mexico Peak and Energy Demand Historical Growth Rate
Exhibit JLR-18	NERC Arizona/New Mexico Peak and Energy Demand Forecast
Exhibit JLR-19	Unplanned and Firmly Planned Builds
Exhibit JLR-20	Capacity Price Forecast
Exhibit JLR-21	Western U.S. Trading Hubs
Exhibit JLR-22	Historical Volume
Exhibit JLR-22a	Palo Verde On-Peak Trade Volume
Exhibit JLR-23	Average Annual Prices
Exhibit JLR-23a	Palo Verde On-Peak Energy Prices
Exhibit JLR-24	Total WECC Firm Builds

I. INTRODUCTION.

Q. Please state your name, position, and business address.

A. My name is Judah L. Rose. I am a Managing Director of ICF International ("ICF"). My business address is 9300 Lee Highway, Fairfax, Va. 22031.

Q. Please summarize your educational background and professional qualifications.

A. After receiving a degree in economics from the Massachusetts Institute of Technology (MIT) and a Masters Degree in Public Policy from the John F. Kennedy School of Government at Harvard University, I joined ICF in 1982. I have worked at ICF since then and now direct ICF's wholesale power practice. I have also been a member of the Board of Directors of ICF International and am one of three people in a firm of over 1,800 people to have been given the honorary title Distinguished Consultant. For additional details, please see my resume, Exhibit JLR-1.

Q. Do you have public sector clients?

A. Yes. ICF has been the principal power consultant to the U.S. Environmental Protection Agency ("EPA") continuously for 25 years. ICF recently conducted the Federal Energy Regulatory Commission's ("FERC") study of electric transmission policy. We have worked with the US Department of Energy, Environment Canada, and numerous foreign governments. We have also worked with state regulators and state energy agencies, including those in Kentucky, New Jersey, California, Texas, New York, Ohio, Connecticut, and Michigan.

Q. Do you have private sector clients?

A. Yes. ICF provides assistance to electric utilities including Duke Ohio, Dominion Power, Delmarva Power & Light, FirstEnergy, and Florida Power & Light, financial institutions

including Credit Suisse, power marketers including Mirant, fuel companies including Peabody Coal Company, and independent power producers including Sithe Global Power, Kelson Energy and Reliant Energy. ICF also works with Regional Transmission Organizations ("RTOs") including MISO and PJM.

Q. What type of work do you typically perform?

A. I have extensive experience in assessing prices and supply and demand conditions in wholesale power markets, including the WECC, and valuing power plants. This work often supports strategic decision-making for developers and investment decisions for the financial community. For example, we have supported the financing of tens of billions of dollars of new and existing electric generating power plant investment and acquisition via the provision of due diligence independent market assessment services.

Q. Do you have other relevant experience?

A. Yes, I have testified in many legal proceedings. For example, I testified in the largest stranded cost case in U.S. history and in the largest U.S. bankruptcy filing in terms of the amount of generation capacity at that time. In addition, I have authored numerous articles in industry journals and spoken at scores of conferences.

Q. Have you been successful in forecasting wholesale power prices?

A. As early as 1995 in a published article, I forecasted that prices would reach thousands of dollars per MWh and made numerous warnings that this was imminent in late 1997 and early 1998. Midwest power prices reached these historically unprecedented levels in 1998 and in 1999. I have a similar record in California and the West where I warned on national television in 1999 that the West was the single worst source of concern for power shortages and price spikes.

Q. Have you testified before, or made presentations to, regulators and legislators?

A. Yes. I have testified before the Federal Energy and Regulatory Commission, and testified or made presentations to State regulators and legislators in New Jersey, Indiana, Ohio, California, Oklahoma, Arkansas, Louisiana, North Carolina, South Carolina, New York, Pennsylvania, Florida and Minnesota.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Tucson Electric Power Company ("TEP").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is twofold. First, I present ICF's Base Case valuation of TEP's generation assets which include coal, combined cycle, gas steam and combustion turbine units located in Arizona and New Mexico. In doing so, I describe ICF's approach to valuation including its computer modeling of the wholesale power sector, and discuss the key drivers of ICF's Base Case valuation including electricity demand growth, power plant construction, natural gas and coal prices, new power plant costs, environmental regulations and transmission. Second, I provide an overview of the wholesale power market that TEP participates in, and reach certain conclusions regarding the state of competition in this market.

Q. How is the remainder of your testimony organized?

A. The second section summarizes my testimony. The third section presents ICF's valuation modeling approach. The fourth section summarizes ICF's modeling assumptions. The fifth section discusses results of ICF's Base Case valuation of TEP's generation assets.

II. SUMMARY.

Q. What are your principal conclusions regarding the value of TEP's owned generation?

A. TEP's total owned generation portfolio is heavily coal dominated and includes 980 MW (60 percent) of coal, 187 MW (11%) of combined cycle, 267 MW (16%) gas steam and 217 MW (13%) of combustion turbine capacity. ICF values TEP's total portfolio at $2.830 billion[1] in 2006 real dollars. This value is nearly five times its book value. This value excludes TEP's leased assets, the Springerville-1 and Sundt-4 coal units. as well as 5 MW of solar generation capacity owned by TEP.

This value is based on a discounted cash flow or income analysis, though a replacement cost approach would yield roughly similar results and provides qualitative support to the valuation. This result is associated with the high prices for power in the wholesale power market relative to the operating costs of coal plants and is corroborated by high natural gas prices, recent construction of new coal power plants, and access to low cost coal by virtue of minemouth locations. This valuation also includes treatment of potential CO_2 emission regulations. TEP's coal portfolio is valued at $2.634 billion or $2,689/kW in real 2006 dollars and accounts for nearly 93% of the total portfolio value. These existing plants have many advantages including already installed pollution control equipment which decreases future capital expenditure needs. TEP's combined cycle portfolio is valued at $114 million or $611/kW in real 2006 dollars and accounts for approximately 4% of the total portfolio value. Finally, TEP's combustion turbine portfolio is valued at $82 million or $376/kW in real 2006 dollars and accounts for nearly 3% of the total

[1] Discounted to January 1, 2007.

portfolio value. TEP's older gas steam units, which are used primarily for reliability must-run purposes, have minimal value on a discounted cash flow basis.

Q. What are your principal conclusions regarding the state of the wholesale power market in the Southwest United States?

A. I conclude that the wholesale power market for TEP customers is robust, very large compared to the TEP load, and vastly improved since the 2000-2001 crisis. Specifically:

- TEP Load is Relatively Small – The smaller the load, the greater the number of suppliers that can compete to meet this load. TEP load is approximately ten percent of total AZ-NM load, and two percent of total WECC load.
- Market Robustness - FERC has determined that TEP has market based rate authority after reviewing the competitiveness of the market. This is one factor contributing to the conclusion that the wholesale power market is robust. Many of the other factors are listed below.
- Improvements in the Market Since 2000-2001 – There are several very important improvements in the wholesale markets which contribute to the view they are robust, including:
  - By 2010, firm WECC US new power plant builds will be 53,000 MW compared to a 2006 summer peak of approximately 131, 000 MW. This supports that the view that the WECC market can respond to meet capacity needs. This is critical since the greatest stress in the market occurs when capacity is short.
  - California has adopted formal resource adequacy rules significantly facilitating capacity expansion, and plans to adopt a Locational Marginal Pricing approach to transmission congestion similar to eastern systems. This system will facilitate market monitoring. In combination, this represents important states to reforms in the treatment of capacity

expansion in a market context.

- Price caps are still in place for short term transactions, and recent enforcement actions for failure to report on a timely basis emphasize the ongoing importance of these controls. At the same time, longer term transactions have less stringent controls, thereby facilitating the transactions need to support capacity expansion.
- The Energy Policy Act of 2005 has greatly enhanced the enforcement authority of FERC, and lead to the creation of an Electric Reliability Organization currently implementing mandatory standards for the entire industry. This eliminates the problems associated with some entities not being subject to FERC regulation, and replaces voluntary standards.
- FERC anti-manipulation rules are very sweeping and are capable of addressing the actions that occurred in the markets in the past.
- The Energy Policy Act of 2005 creates a system of extremely strong potential fines, and resolve any uncertainty regarding the authority of FERC to strongly penalize manipulation or other rule violations.
- The anti-manipulation rules mentioned above supplement range of FERC mechanisms, FERC Mergers and Acquisition oversight under Section 203, triennial market based rate authority review, FERC transaction data collection, and rules regarding index reporting.

III. VALUATION APPROACH.

Q. What are the principal methods for valuing generation assets?

A. There are three commonly used approaches to valuing in-use assets: the replacement cost approach, the comparables approach, and the income (or discounted cash flow) approach. However, as discussed below, we rely on the income approach for our quantitative results

and believe it is most appropriate for power plants.

Q. How is the replacement cost approach performed?

A. The replacement cost approach is based on the concept of replacement or reproduction cost as the indicator of value. An investor would pay no more for an asset than the amount that it would cost to replace it with a new one. To the extent the asset being valued has physical deterioration (e.g., wear and tear), functional obsolescence caused by advances in technology, and economic obsolescence, e.g., increased costs due to environmental regulations, the cost of replacement would be adjusted for the above losses in value. For example, the all-in cost of a new super-critical pulverized coal unit today would be close to [redacted] in real 2006 dollars. As applied to the 980 MW of coal would result in a valuation of roughly [redacted][2].

Q. What role does the replacement cost approach play in your valuation?

A. The replacement cost plays a qualitative role and in this case corroborates my valuation.

Q. Why does it play only a qualitative role?

A. The underlying assumption is that replacement is appropriate. In some cases, in markets with excess capacity, purchases from the market are more economic than replacement. Conversely, when there are long lead times, construction risks, and replacement is difficult due to permitting problems, existing units can have a premium value. In other cases, a different asset is more appropriate for replacement. These issues are ultimately resolved in the income approach as are the related categories of physical deterioration, functional obsolescence, and economic obsolescence. Since the income approach is needed to apply the replacement method, I did not use replacement cost as a basis for a

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[redacted]

quantitative estimate, but rather used the income approach. I note that replacement costs are inputs into the income approach as discussed later in my testimony.

Q. How is the comparables approach performed?

A. The comparables approach involves a direct comparison of the subject asset to similar assets that have sold in the market, in order to derive a market value indication for the asset being appraised. The price that a typical purchaser pays for a comparable asset is usually the result of an extensive process in which alternative assets are compared. Similar to the replacement cost approach, the comparables approach relies on the principle of substitution. This approach implies that a prudent investor will not pay more to buy the asset that it will cost to buy a comparable asset.

Q. What role does the comparables approach play in your valuation?

A. I did not use this approach. In this case, there are no comparable transactions, especially for the coal plants. Furthermore, as a general matter, the comparables approach plays a qualitative role because it is often difficult in the generation sector to find assets that are fully comparable. This difficulty in finding comparables reflects lack of sales relative to the diversity of the assets. This diversity reflects differences in fuel, technology, vintage, location, costs, and power sales contracting status (e.g., long-term PPA, etc.). In the end, these differences need to be resolved via the income approach, reinforcing the importance of the income approach.

Q. How is the discounted cash flow approach performed?

A. A discounted cash flow ("DCF") approach analyzes the future profits of an asset by projecting revenues and expenses and applies a discount rate take into consideration the time-value of money. In developing the appropriate discount rate, business risk is considered and rates of return from similar other investments must are analyzed.

Q. Which is the widely accepted approach to generation asset valuation in the electric power industry?

A. The DCF approach is most widely used by bidders for existing power plants, developers of new plants, and the financial community to establish power plant valuations. This is because it is the theoretically correct approach addressing all components of value, and is needed to support the other two approaches for reasons discussed above. This is the reason that discounted cash flow analysis is widely used and essentially universally accepted in the wholesale power industry and with the financial community.

Q. What information is needed to undertake a discounted cash flow analysis?

A. Under a DCF analysis, the forward-looking value of the asset is the present value of the net cash flows, i.e., profits derived from use of the asset during its lifetime. Generally, for power plants, several assessments are necessary to estimate the expected cash flows. These include the following:

- **Wholesale Electricity Prices** - Prices paid for the output of the plant are key determinants affecting its value. For a merchant power plant operating in a deregulated market, prices realized by the plant equal the market clearing prices of electricity during the hours of operation of the plant.
- **Plant Dispatch** - The output of the plant depends on the capacity, the expected lifetime, the reliability of the unit, and the unit's competitiveness. The same modeling approach for determination of future prices also provides a simultaneous

assessment of plant dispatch.

- **Plant Cash Going Forward Costs** - The cost of producing the plant's output depends on fuel prices, operational characteristics of the plant (heat rate, minimum turndown), future capital, and non-fuel operation and maintenance expenditures.
- **Debt** - Debt and interest rates and debt schedules for leverage used by a plant buyer and for future capital expenditures also affect the cash flow available to equity owners.
- **Discount Rate** – The discount rate converts future cash flows into a present value. For this analysis, we are using the weighted average cost of capital ("WACC") using merchant financing assumptions to discount each year's cash available for equity distribution to shareholders.

Q. What computer model did you use to forecast wholesale electricity prices and plant dispatch?

A. I used ICF's IPM® model. Developed by ICF, IPM® is a multi-regional, dynamic, linear programming model of the U.S. electric power sector with treatment of coal, natural gas, and environmental issues. This model is sufficiently sophisticated to develop an integrated set of national and regional forecasts.

Q. Does the U.S. EPA use this same model?

A. Yes. This is the principal analytic tool used by the U.S. EPA to analyze the electric utility generation and transmission sectors. ICF has used this and similar predecessor models over the last 30 years nearly continuously for EPA to assess the impacts of air pollution regulations on the power sector. For example, ICF has modeled cap and trade emission control options for EPA since 1975, over 30 years ago.

Q. Is this model widely accepted in the public sector beyond the U.S. EPA?

A. Yes, IPM® is also widely used by other governmental entities including DOE, FERC, state agencies, and Environment Canada.

Q. Is this model widely used for private sector clients?

A. Yes, the IPM® model has been widely used by private industry to analyze the electric power sector in the 48 contiguous states and the District of Columbia. A very large percent of U.S. utilities have used IPM® results for planning activities. The model has also been widely used to address other electric power issues.

Q. Why did you use this model?

A. The IPM® model has many advantages including:

- It models all U.S. power plants simultaneously. This is important for several reasons. First, power pricing is set by the marginal unit's production costs, and hence, units cannot be analyzed in isolation. Second, power transmission between regions is a key factor as lower cost and lower emission profile power can be imported or exported. Third, the effects on fuel markets of fuel demand across regions need to be addressed on an integrated basis in order to determine fuel market prices. Fourth, emission allowance pricing is set by the marginal unit's compliance costs, and hence, also cannot be analyzed in isolation.
- It models all years simultaneously, not sequentially. This is important for two reasons. First, capacity expansion decision-making requires a coherent set of expectations about future conditions, including the fact that today's investment affects markets in later years.
- Second, the CAIR and CAMR programs allow for the banking of emission allowances. Thus, allowance value in one year must be compatible with values in other years. For example, if allowance prices are expected to be very high in the

future, companies could bank allowances if current prices are too low and sell them in later years. One would expect equilibration between prices in different periods.

- It handles the four key air emissions – SO_2, NO_x, Hg, and CO_2. This is important in light of the interrelated effects of the regulations, especially the co-benefit phenomenon between NO_x, SO_2, and mercury. For example, the costs of controlling SO_2 on a dollar per ton SO_2 removed might be significantly less after factoring in the decrease in mercury emissions in scenarios in which mercury allowance prices are very high.
- It handles multiple industries on an integrated basis. The model simultaneously simulates in whole or in part the power, coal, coal transportation and natural gas industries. This is important because fuel switching is a compliance option and large shifts in fuel use could affect fuel prices.
- It simultaneously integrates the analysis of capacity expansion with the fuller set of electric operations such as power plant dispatch, plant modification, and retirement, transmission flows, fuel choice, and environmental compliance.
- It simultaneously models physical operations and prices including wholesale power prices.

Q. What is the conceptual approach to forecasting capacity expansion, allowance prices, fuel, and wholesale power prices underlying ICF's IPM® model?

A. The model simulates competitive supply and demand conditions and forecasts the least cost solution. It should be emphasized that the results are the least cost option for the industry given the regulations and other constants facing the industry. In this approach, prices equal marginal costs. This pricing approach applies to all commodities including fuel, wholesale electric power and emission allowance prices.

Q. What types of information are used in the modeling?

A. The simulation is conducted using six main categories of information: (1) hourly demand for electricity and customer demand for sufficient capacity to ensure reliable firm generation service, (2) fuel market conditions and plant fuel options, including various coal sulfur, and mercury contents, (3) information about every existing power plant (*e.g.*, capacity, operating costs, environmental characteristics, power plant operating constraints, *etc.*), (4) information on the potential for entry and exit of power plants (*e.g.*, new potential plant cost and performance characteristics, costs to keep existing units operating), (5) environmental constraints and power plant emission control options, and (6) the major transmission interfaces between zones or grid sub-regions. As noted, the output of the simulation includes a large number of parameters such as new power plant construction costs and performance, existing and new plant operations, fuel choice, transmission flows, fuel, wholesale power, and allowance prices, *etc.*

Q. How does the model calculate wholesale power prices?

A. The model is required to supply to each region specified quantities of electrical energy and capacity available to meet reserve margins. The model covers all of North America power demand. Hourly electrical energy prices reflect the hourly marginal cost of electrical energy supply from the incremental source of energy including fuel, variable non-fuel O&M (Operator and Maintenance), allowance and transmission costs. Because fuel and allowance costs are the largest drivers of electrical energy production costs, wholesale power prices are heavily affected by fuel costs and environmental regulations. This model also calculates annual capacity prices reflecting the additional annual revenue beyond that available to power plants in the electric energy market needed to ensure adequate capacity. Capacity costs include fixed annual non-fuel O&M or the annualized investment costs of new units. These annual capacity related costs are recovered during the summer peak periods via price spikes or in capacity markets. These costs tend to be

low when there is excess capacity in the industry and high during periods when the grid's actual reserve level is close to target levels. While these two components are joint products in that power plants provide both services, energy and capacity prices can and are calculated individually and can be bundled to estimate firm prices. Bundled unit contingent firm power supply is the per MWh cost of energy plus capacity.

IV. VALUATION ASSUMPTIONS.

Q. How is your natural gas price forecast developed?

A. Natural gas has a much greater impact on wholesale electric power prices than its share of electricity generation in the Arizona-New Mexico (AZ-NM) marketplace indicates. This is because natural gas is often the incremental generation source, and hence, sets market prices. This is especially true after accounting for the potential for power trading between regions. Higher gas prices raise power prices and valuations and vice versa. The Base Case natural gas price forecast from 2011 onwards is from ICF's NANGAS model which simulates North American natural gas supply and demand under CO_2 regulations. The model has 17 demand regions, 23 supply sources covering 17,000 North American production reservoirs, and covers residential, commercial, industrial, and power demand for natural gas. The model also projects LNG imports. The effect of changing demand for natural gas due to power development is handled in IPM® based on NANGAS results. ICF relied on a combination of recent spot prices and NYMEX trades of Henry Hub futures for the 2007-2010 period. Exhibit JLR-2 shows ICF's natural gas price forecast for Henry Hub and basis differentials to the Arizona and New Mexico markets. The 2007-2036 levelized average natural gas prices at Henry Hub is [redacted] in real 2006 dollars. NYMEX Henry Hub futures prices as of May 15, 2007 for 2007, 2008, and 2009 were $8.53/MMBtu, $8.28/MMBtu, and $7.28/MMBtu, respectively. The 2007 Henry Hub natural gas price used in the analysis is weighted average of YTD spot and the

NYMEX future prices for the remainder of the year as of May, 2007. The 2008 and 2009 prices used in the analysis are NYMEX futures prices quoted in May, 2007 for delivery into 2008-2009. Prices in 2010 are an average of the 2009 futures price and the 2011 fundamentals-based forecast. Prices from 2011 onwards are based on the ICF fundamentals forecast.

Q. How are coal prices forecasted?

A. Coal is the most heavily used electric generation fuel in the U.S., and in the AZ-NM market. In the AZ-NM market, coal accounted for about of 51 percent of 2005 generation. Also, nearly all coal is used in electric generation. Accordingly, coal receives the most detailed treatment in the IPM® model. IPM® is used to forecast coal prices, coal transportation, coal production and coal consumption. Approximately 41 coal demand and 40 coal supply regions are modeled in IPM®, and multiple quality coals are modeled regarding sulfur, Hg, rank, and heat content. Exhibit JLR-3 shows ICF's price forecast for Wyoming Powder River Basin (PRB) 8,800 Btu/lb coal with prices averaging [redacted] on a levelized basis in real 2006 dollars for the 2007-2036 period. However, most coal used by TEP is minemouth coal. We rely on TEP coal price forecasts for these units.

Q. How long of a time period did you simulate?

A. The simulation was conducted over 30 years (2007 – 2036). This was done to incorporate information about new supply options, endogenously project the entry and exit of power plants, and account for the price trajectory of the power, fuel and emission allowances. No termination value was calculated in light of the long time period in the analysis and the low present value of cash flows or costs thirty years hence.

Q. How does the model treat generation capacity expansion?

A. The model separately treats firm and non-firm power plants. Firm new power plants – *i.e.*, those already under construction – are assumed to come on-line at pre-specified levels (See Exhibit JLR-4). Unplanned power plant construction decisions are made by the model (*i.e.*, type, amount, timing, location) to minimize costs of producing power taking into account alternatives such as power imports, greater use of existing plants, or less retirements, and mothballing of existing units. Exhibits JLR-5, JLR-6, JLR-7, and JLR-8 describe the costs and characteristics of unplanned power plants.

Q. What does the base case assume regarding environmental regulations?

A. The Base Case assumes that utilities must comply with existing environmental regulations, notably the CAIR (Clean Air Interstate Rule) and CAMR (the Clean Air Mercury Rule). However, none of western states are part of the CAIR program. Moreover, Arizona is part of the CAMR cap-and-trade program while New Mexico is currently part of a 16-state coalition in lawsuit with EPA opposing the CAMR rules. In addition, the Base Case includes an expected national CO_2 control program based on a probability-weighted outcome of several potential CO_2 reduction trajectories in turn based primarily on analysis of proposed legislation.

Q. What is the Clean Air Mercury Rule (CAMR)?

A. The Clean Air Mercury Rule is the first regulation from EPA to substantially cut mercury emissions from coal-fired power plants. CAMR is a cap and trade program covering U.S. power plants. The cap in 2018 is 15 tons. Currently, New Mexico is the only western state that has opted out of the CAMR program.

Q. Please describe ICF'S expected CO_2 regulations.

A. There are currently no federally mandated requirements to reduce CO_2 emissions and, therefore, there continues to be significant uncertainty not only on the timing and stringency of such controls but also how power plants would be allocated allowances in a possible cap and trade regime. ICF's Base Case CO_2 allowance price trajectory is a probability-weighted outcome of projections of four recent policy proposals and an international market price used to develop that trajectory. As shown in Exhibit JLR-9, CO_2 allowance prices start out at [redacted] in 2013 in real 2006 dollars and increase in real terms as the probability of a more stringent policy increases over time. ICF has assumed that existing power plants will receive CO_2 emission allocations. ICF also assumes that plants that come on-line in the near future receive CO_2 emission allowance allocations. There is uncertainty about what will be the baseline for determining the level of allocations. One possibility would be pre-2007 levels; another is levels as late as 2015 or later. As an average and in recognition that in this case, the results are not very sensitive to the baseline period, the allocations are based on 2010 MWh baseline generation, including all fossil and incremental nuclear generation since 1990. The allocation rate in each year equal to CO_2 emissions resulting from the IPM® national run in that year divided by a fixed baseline MWh. A fifteen (15)-year transition from 75% allocation (after 25% set aside for other purposes, e.g., renewables, energy efficiency) in 2013 to full auction in 2028.

Q. What was assumed about new renewable power plants?

A. ICF assumed a regional renewable portfolio standard in the WECC region in which renewable generation of one state was qualified to meet the renewable requirements of another state. Supply curves for resources are specified regionally for wind and biomass while limits exist for landfill gas, solar thermal, photovoltaic, and geothermal. The Production Tax Credit is phased out through 2009.

Q. What assumptions were made in the base case regarding electricity demand growth?

A. ICF projects that electricity demand will grow modestly slower than the historical average. ICF projects that peak electricity demand growth will average 3.5% in the AZ-NM market from 2007 to 2036 (see Exhibit JLR-10). This compares with the ten year rolling average AZ-NM peak demand growth rate of 4.1 % from 1985 to 2005. During the same period, electrical energy growth in AZ-NM is projected to grow at 3.2 % per year.

Q. What assumptions were made in the base case regarding firm builds?

A. The model assumes 215 MW of firm builds in AZ-NM in 2007 and none thereafter. Thus, all builds in the AZ-NM region post 2007 are model forecasts, *i.e.*, non-firm builds.

Q. What assumptions were made regarding planning reserve margins?

A. Currently, there are no near-term plans to implement an RTO in the Southwest under WestConnect. Conservatively, planning reserve margins for AZ-NM are set at levels below those of most RTOs, *e.g.*, 15 % in 2007 and declining to 13% by 2036. To the extent planning reserve margins are higher than the 13 – 15 % range, the demand for capacity will be greater than forecast.

Q. What assumptions were made regarding electricity transmission?

A. It was assumed that there would be no changes in inter-regional transmission capability, and no congestion within regions. Actual flows were determined by the model. ICF modeled the entire North American grid with a focus on the Western Electricity Coordinating Council (WECC). Exhibit JLR-11 shows the IPM® model regions in WECC that were explicitly modeled in this study.

Q. Please describe the parameters of TEP's generation assets underlying ICF's DCF analysis.

A. ICF used its IPM© model to forecast wholesale market power prices for the Arizona, New Mexico and Four Corners/San Juan model regions and economic dispatch of each of the TEP generation assets. The forecast of electrical energy and capacity revenues for each of the units was put into ICF's DCF model. The net capacity, coal fuel prices, O&M and capital expenditures were provided by TEP (see Exhibit JLR-12).

Q. What are the financing assumptions underlying ICF'S DCF analysis?

A. ICF assumes financing terms from the perspective of a third-party buyer who would sell electricity to the wholesale market on a merchant basis. Exhibit JLR-13 shows the financing assumptions used in TEP's DCF analysis.

V. VALUATION RESULTS.

Q. Please summarize your base case valuation results for the TEP generation asset portfolio.

A. ICF's Base Case valuation is summarized in Exhibit JLR-14. ICF's Base Case assessment shows that the TEP's total portfolio is valued at $2.830 billion[3] in 2006 real dollars or nearly five times its book value. TEP's total portfolio includes 980 MW (60%) of coal, 187 MW (11%) of combined cycle, 267 MW (16%) of gas steam capacity and 217 MW (13%) of combustion turbine capacity. TEP's coal portfolio is valued at $2.634 billion or $2,689/kW in real 2006 dollars and accounts for nearly 93% of the total portfolio value. TEP's combined cycle portfolio is valued at $114 million or $611/kW in real 2006 dollars and accounts for approximately 4% of the total portfolio value. Finally,

[3] Discounted to January 1, 2007.

TEP's combustion turbine portfolio is valued at $81.6 million or $376/kW in real 2006 dollars and accounts for nearly 3% of the total portfolio value.

Q. Please provide unit-level details on the valuation of TEP's coal generation portfolio.

A. ICF's valuations of TEP's coal portfolio are summarized in Exhibit JLR-15. Values for each coal unit range from a low of $1,764/kW to a high of $3,519/kW.

Q. Please describe ICF's expected firm electricity price forecast.

A. Firm all hours prices for Arizona start at $62.8/MWh in 2006 dollars for 2007 and increase in real dollars [redacted] per year on average. This price is the sum of pure capacity spread over the hours of the year and electrical energy prices and represents unit contingent firm supply. In nominal dollars, assuming 2.5 percent general inflation, prices increase [redacted] per year (see Exhibit JLR-16). This price trend reflects strengthening capacity prices and trends in electrical energy prices in real terms. As electricity demand grows, it catches up with past generation capacity additions and power prices rise to the levels needed to support and permit additional power plant construction.

Q. Please describe ICF's expected energy price forecast.

A. Electrical energy all-hours prices increase slightly in real inflation-adjusted terms in the forecast period. Between 2007 and 2010, [redacted]. This price pattern is due to several opposing factors. First, gas-fired generation in the WECC is often marginal, with more inefficient natural gas and oil-fired units setting prices in the on-peak while efficient combined cycles set prices in off-peak periods. In the near term (2007-2009), the rise in natural gas prices tends to lead to displacement of natural gas units by coal-fired units dispatching at lower variable costs in some off-peak segments. Arizona and New Mexico are close to inexpensive coal resources which also help drive substitution between coal and gas at higher gas prices.

Subsequently, in the mid-term (2010-2014), energy prices are expected to fall as natural gas prices decrease, although the reduction in energy prices is expected to be moderated by the need to dispatch less efficient units, with higher heat rates and variable costs, to meet rising energy demand. It should be noted, long-term average electricity demand growth has been growing steadily in Arizona and throughout the WECC (see Exhibit JLR-17) in spite of consistently too low forecasts by the utility industry generally (see Exhibit JLR-18.) In the long-term (2016-2036), new efficient base load units with low heat rates and variable costs are built to satisfy energy demand. While natural gas prices are forecast to rise over the long-term, the increase in natural gas prices is expected to be proportionally greater than that of energy prices due to the efficiency of the newly constructed base load coal and gas-fired units.

Q. Is there a way to express your electrical energy power price forecast correcting for the level of natural gas price forecasts?

A. The implied system heat rate is shown in Btu/kWh and is a useful rule-of-thumb for expressing wholesale power prices as a function of natural gas prices. Implied system heat rate is calculated by dividing the wholesale electricity price by the delivered natural gas price. The implied heat rate metric corrects for the effects of natural gas prices which is an uncertain parameter. This is important since TEP's coal plants generally compete against natural gas plants, and their dispatch is limited only by availability. Therefore, their revenues for electrical energy sales can be expressed as a function of natural gas prices and the efficiency of the market expressed by the implied system heat rate. The higher the heat rate the greater the margin available for a given gas price. In 2007, if one assumed that natural gas-fueled plants were always the price-setting unit for all hours electrical energy prices and had a heat rate (*i.e.*, a thermal efficiency for converting fuel energy to electrical energy) of 8,370 Btu/kWh, then the electricity price would equal $62.8/MWh in real 2006 dollars. Of course, the actual IPM® modeling does not assume natural gas is on the margin setting prices all the time. Prices are generally set by

natural gas units of varying efficiencies. By 2009, the implied system heat rate declines to [redacted], as renewable generation units are built in the WECC to meet renewable energy requirements and coal units begin to replace gas on the margin. Implied heat rates thereafter rise from 2010 through 2013, reflecting a sharp drop-off in new additions and increased reliance on dispatch of less efficient gas-fired units to meet base load energy demand. Post-2013 implied heat rates gradually decline as more efficient and low variable cost base load combined cycle and coal units (mostly coal IGCC) come online.

Q. What new power plants are built in Arizona and New Mexico in the base case forecast?

A. In the Base Case forecast, new power plants currently under construction are assumed to be operational by their on-line date. In other words, no plants already under construction are cancelled in spite of the current excess capacity and depressed power prices for peaking plants. However, this means there will be a sharp drop off in additions because almost no new plants under construction are scheduled for completion in 2008 or beyond. These plants under construction are referred to as firm additions. The model also builds new plants based on the economics of supply and demand. These new plant builds are referred to as non-firm or unplanned builds. In the near term, the model chooses to primarily build new natural gas-fired peaking power plants through 2010 to meet reserve margin targets, and new renewable power plants to meet state renewable portfolio standards. By 2013, construction of new power plants to serve base load energy needs will be needed in Arizona and New Mexico. After 2015, mostly base load units in the form of coal-fired and natural gas-fired power plants are expected to be built in the AZ-NM region (see Exhibit JLR-19).

Q. What are the wholesale power pricing consequences of this build forecast?

A. As mentioned, the scarcity component of pricing is depressed in the near-term relative to equilibrium levels. This scarcity component is also known as the pure capacity price and equals on an annual per kilowatt basis the price spike revenue available to all units. Price spikes are prices above the marginal short run variable costs of plant operation. They are necessary to ensure sufficient capacity (hence the name capacity price) to provide customers reliable supply. In other words, a market without price spikes (or equivalent substitutes) forever will fail to provide reliable supply (*i.e.*, there will be blackouts.) Exhibit JLR-20 shows ICF pure capacity price forecast for the Base Case. Capacity prices are one of two components of firm prices and the smaller of the two. This component is not observable in most markets since the transactions are bundled with a single $/MWh price. However, the capacity price is needed since the bundled firm price is analytically estimated as the sum of the capacity price and the electrical energy price or system lambda.

Q. Please discuss the capacity price forecast.

A. Capacity markets in the WECC are expected to return to equilibrium [redacted]. Prior to 2010, the capacity price forecast [redacted]. Beginning in 2010, the price of reliability services, i.e., capacity prices, will be set by the fixed and capital costs of newly constructed peaking units. After 2010, capacity prices decline and level out at about [redacted] as more base load combined cycle and coal units are built and, thus require less capacity premiums to cover their annual fixed costs.

Q. Do the fossil-fired units earn revenues from emission allowances?

A. All of TEP's generation assets are expected to receive revenues from CO_2 allocation, which account for 2.8 percent of gross revenues. Allocations due to TEP coal generation assets account for 90.4 percent of total CO_2 allocation revenues. Additionally, TEP's

coal portfolio receives additional SO_2 allocation revenues which account for 3.6 percent of gross revenues.

Q. Please discuss costs realized by TEP generation assets.

A. TEP generation assets are expected to pay operations and maintenance costs, fuel costs, emissions costs, and costs related to ongoing capital expenditures. Fuel, operations and maintenance costs, and costs of ongoing capital expenditures and pollution control retrofits are based on TEP input data, while costs of emissions are based on emission rates for the coal units provided by TEP and on ICF's forecast of allowance prices. Total costs are equal to 47 percent of gross revenues. TEP's coal portfolio accounts for 86 percent of the total production cost.

Q. Please discuss pollution control retrofits to the TEP generation assets.

A. Several TEP units are scheduled to add emissions retrofits to meet regional and national environmental compliance standards. TEP units located in New Mexico are expected to come under a state-level MACT (maximum achievable technology) standard for Mercury emissions, while TEP units located in Arizona are expected to participate in the EPA CAMR cap and trade program for Mercury emissions. Units in both states are expected to participate in the CAIR SO_2 cap-and-trade program. San Juan units 1-2, located in New Mexico and under MACT, are scheduled to add controls to reduce Mercury emissions by 50% in 2010. Springerville, located in Arizona and a participant in the CAMR cap and trade program, is scheduled to add an ACI unit in 2010. Additionally, Navajo units 1-3 are scheduled to add low-NO_x burners in 2011, and San Juan units 1-2 are scheduled to add low-NO_x burners in 2009. ICF also allows the model to choose additional pollution control retrofits to meet MACT standards or reduce costs of emissions under cap and trade. Navajo units 1-3 are expected to add ACI controls in 2036 to reduce CAMR costs. San Juan units 1-2 and Four Corners units 4-5 located in

New Mexico are expected to add ACI controls in 2020 to comply with Phase II of the New Mexico MACT standard.

VI. WHOLESALE POWER MARKETS.

Q. Please describe the organization of the WECC markets.

A. There are several features of the WECC market that are worth noting at the outset:

- Under the Federal Power Act, FERC has regulatory oversight over wholesale power. The Energy Policy Act of 2005 has greatly enhanced the authority of FERC.
- One of the key features of the Energy Policy Act of 2005 is to create - for the first time – a nation-wide organization that has the authority to develop and enforce mandatory reliability standards for the bulk electric industry. On April 4, 2006, the North American Electric Reliability Council ("NERC") submitted to the FERC an application to become the nation's sole electric reliability organization along with a petition of 102 reliability standards for approval.[4] On July 20, 2006, the FERC accepted the NERC's application and paved the way for a mandatory compliance regime. Currently, the FERC has approved 83 standards due to become enforceable on June 18, 2007. The coming mandatory reliability standards have created a large change for all industry participants. Congress has empowered the FERC to apply the standards to "any regional entities and all users, owners and operators of the bulk-power system"[5]. This includes entities that previously did not fall under the FERC's jurisdiction such as municipal and

[4] However, this process is not entirely sequential. The NERC, via its various ballot bodies, is still revising and approving more standards and by August 20, 2006, there were 118 standards that had received NERC Board of Trustee (BOT) approval – an increase of 16 new standards since April 4, 2006.

[5] Energy Policy Act 2005 revision to Federal Power Act, Section 215(d)(1).

cooperative utilities, federal power marketing agencies, as well as independent power producers ("IPPs"), and non-traditional asset owners (i.e. financial institutions).

- Under the Energy Policy Act of 2005, the authority exists to issue very extensive civil penalties for non-compliance up to $1 million per day per incident upon a finding of wrong-doing. Prior to the Energy Policy Act of 2005, NERC rules were voluntary and NERC had no enforcement authority.
- The Western Electric Coordinating Council ("WECC") is a member of NERC and is focused on the reliability of the Western Grid which covers the U.S. areas roughly west of the Colorado Nebraska border extended north and south as well as two Canadian provinces, Alberta and British Columbia.
- Within the WECC geographic footprint, very large electric transmission capabilities exist between its sub-regions, notably between the Desert Southwest and Pacific Northwest and California. The total into-California transfer capability is the largest in the U.S., and includes both DC and AC components. California is the largest power importing state in the U.S. This large inter-regional grid was created to move coal power from the southwest to California, and from large minemouth plants to utilities in California and Arizona, and to move hydroelectric power from the Colorado River system and the Pacific Northwest. This transfer capability facilitates substantial commercial activities as well.
- Under the Energy Policy Act of 2005, FERC has the authority under some circumstances to provide eminent domain to build new transmission lines.
- Utilities in California divested most of their fossil generating capability. As a result of this divestiture and new plant construction by non-utilities, generation capacity is widely distributed among independent power producers in addition to utilities.

Q. What type of commercial organization exists among the wholesale power market?

A. There are two broad types. The first is one in which bilateral or exchange transactions predominate, but the exchange is not run by the power industry. In this market, entities transact for power, transmission rights across utility territories and ancillary services. The second involves Regional Transmission Organizations which cover multi-utility footprints and operate markets. In cases where the market uses Locational Marginal Pricing ("LMP") pricing, grid access is bid based, and prices reflect bids and congestion costs.

Q. What is the commercial organization of the wholesale power markets in AZ-NM and in adjacent regions?

A. Currently, wholesale markets in the AZ-NM region, and in the Western Interconnection generally, are organized on a bilateral basis. There are active bilateral markets at the Palo Verde, Four Corners, SP-15, NP-15, COB, and Mid-Columbia trading hubs (see Exhibit JLR-21). Physical and financial electricity products are actively traded through brokers with these hubs as pricing points. The principal exception to this rule is the California Independent System Operator ("CAISO") which operates the only regional transmission organization ("RTO") in the WECC region. Outside of CAISO, there are no central dispatch and balancing authorities. However, unlike most of its counterparts in the East, CAISO does not currently operate nodal day-ahead LMP markets. Under the current market design, CAISO markets are bilateral with a balancing market that treats congestion zonally rather than nodally. California is expected to adopt LMP by January 31, 2008.

Q. Please summarize briefly the commercial organization of the natural gas markets.

A. Natural gas markets are also subject to FERC jurisdiction. Gas trades both bilaterally and via exchange products. The NYMEX Henry Hub natural gas futures contract is heavily

traded. Basis difference futures are also traded. There is also extensive over-the-counter bilateral trading. Liquid natural gas trading hubs exist at Topock and San Juan as well as other locations.

Q. Why is this relevant?

A. Power prices are heavily influenced in the WECC market by natural gas prices as natural gas plants are often marginal price setting units.

Q. Please describe TEP's share of the total wholesale market in AZ-NM and in the WECC.

A. TEP's share of the market is a small facility competitive service from multiple providers. In 2006, Arizona generating capacity was approximately 26,500 MW. AZ-NM-SoNev peak load was 28,685 MW. In 2006, TEP peak load in AZ-NM was 2,550 MW or about 10% of the total Arizona load or 8% of AZ-NM-SoNev load. US WECC load totaled 131,403 MW in 2006 and deliverable capacity totals 187,000 MW (NERC Summer Assessment). TEP represents less than 2% of total WECC load.

Q. Please describe the trading hubs located in or immediately adjacent to the AZ-NM region.

A. There are three hubs located in or near TEP's control area in AZ-NM that act as pricing points for bilateral wholesale market trades.

- **Palo Verde** – The Palo hub is located at the switchyard of the Palo Verde nuclear facility west of Phoenix.
- **Four Corners** – The switchyard of the coal-fired Four Corners power plant in Fruitland, New Mexico located in the Northwestern corner of the state where Arizona, Colorado, New Mexico and Utah meet.
- **Meade** –The switch yard at the Hoover Dam on the Colorado River forming Lake

Mead near Las Vegas Nevada.

Markets are these locations are extremely liquid. For example, trade at the Palo Verde hub reached 29,000 MWh/day in 2006.

Q. How is power typically transacted in the WECC wholesale power market?

A. As noted, power is typically transacted bilaterally on an over-the-counter basis. However, power is also traded on exchanges including a NYMEX futures contract and trading on ICE (InterContinental Exchange). For example, there are for NYMEX power futures: (1) Dow Jones Mid-Columbia Index Futures, (2) Dow Jones Palo Verde Index Futures, (3) Dow Jones North Path-15 Index Futures, and (4) Dow Jones South Path-15 Index Futures.

Q. How is wholesale power typically transacted in power markets?

A. Wholesale power is typically transacted in blocks of power. For example, a supplier would be obligated to provide 100 MW of power for every hour for a fixed period at a market-based price. Most transactions are for fixed blocks of on-peak power. On-peak power is supplied 16 hours a day six days a week (6 AM to 10 PM). Off-peak power is supplied eight hours a day (at night) six days a week and all hours on Sundays.

Q. Are there also other standard terms and conditions?

A. Yes. In addition to these conventions there are often standard contract terms and conditions prepared by such entities as the Edison Electric Institute ("EEI") and the Western System Power contract. EEI facilitated an industry-wide collaboration with the National Energy Marketers Association and others, to develop this model bilateral master agreement containing the essential terms governing forward purchases and sales of wholesale electricity. In January 1999, a group of over 80 EEI member utilities, affiliated

and independent power markets, merchant power, and end-use representatives formed a Working Group and Drafting Committee to prepare the Master contract. The Master Contract provides the following benefits: streamlines establishing a trading relationship; provides "real time" credit provisions; standardizes product definitions; and focuses traders on the transaction's basic negotiable elements, e.g., price, quantity, location, and duration.

Q. How is power priced in bilateral markets?

A. The pricing of power is determined bilaterally between willing buyers and willing sellers. This price is tracked using market indices which in turn are tracked by organizations such as Platts and Dow Jones. Prices can be fixed by mutual agreement or set equal to a market index. Large volumes of power are transacted. Most contracts are for one-year duration or less, but some extend beyond one year.

Q. Describe the volume and liquidity of bilateral markets in the AZ-NM region.

A. Over the past seven years, daily trading volume has ranged from 1,878 MWh to 29,021 MWh on the Palo Verde bilateral markets and 763 MWh to 6,116 MWh on the Four Corners bilateral markets. In general, the trend is toward increasing volumes especially for the off-peak periods (see Exhibit JLR-22 and JLR-22a).

Q. Please describe historical trends in wholesale power prices reported to market index providers.

A. I believe it is useful to identify four historical periods since the deregulation of the wholesale section by FERC in the aftermath of the 1992 Energy Policy Act. The post-1992 deregulation provides for comparable access to the power transmission grid, a key condition for a robust wholesale power market. The four historical periods (see Exhibit JLR-23 and JLR-23a) are:

- The first period is from 1996 to 1999 when wholesale power prices were low in part due to low natural gas prices, high hydro supply and excess capacity.
- The second period is 2000 to 2001 when prices hit record levels. I note that natural gas prices were also high during this period, hydro was low, and peak electricity demand was catching up with supply. It should be noted that this period of high pricing contributed to significant and fundamental changes to the regulation of the wholesale power market that I return to later.
- The third period was 2002 to 2004 when power prices returned to pre-2000 levels and then rose steadily roughly tracking natural gas prices.
- The fourth period is 2005 – 2007 when natural gas prices have been at record levels. In 2005, in particular, wholesale power prices increased as a result of all time record high prices in the natural gas market as a result of hurricanes Katrina, Rita, and other factors. In 2006, power prices declined as natural gas storage levels remained above historical ranges throughout the injection season (April through October). However, in late July 2006, a severe heat wave resulted in 100+ degree temperatures over much of the West - and up to 113 degrees in Las Vegas and 118 degrees in Phoenix. Between July 12 and July 26, peak load records were set by customers of utilities (e.g., Nevada Power, Arizona Public Service, and Tucson Electric Power). Power prices in the Southwest bilateral markets spiked to over $350/MWh on July 24, the date that CAISO declared a Stage 2 Emergency - CAISO's call for critical conservation due to very tight power supplies in its control area.

Q. In light of the problems in the WECC wholesale power markets in 2000 and 2001, what has changed?

A. There have been many changes. The first I want to highlight is the large amount of new power plant supply that has been added since 1999 (see Exhibit JLR-24). Firm WECC

U.S. builds are expected by 2010 to be over 53,000 MW. This compares to a 2006 summer peak of approximately 131,000 MW and does not include Canadian capacity additions.

Q. What are some of the other changes?

A. Next, I want to highlight new FERC anti-manipulation rules designed to protect the wholesale power market.

Q. What are the FERC anti-manipulation rules?

A. FERC has recently implemented an anti-manipulation rule applying to actions post-2005. This rule builds on FERC's Market Behavior Rules adopted earlier in the 2003-2005 period, and is also modeled on the SEC anti-manipulation rules. In the event of intentional manipulation of the market, the violator is subject to new civil penalties authorized by the Energy Policy Act of 2005. These penalties include disgorgement. In addition, violators are subject to $1 million penalties per instance per day. For example, if a trader makes 100 trades to manipulate the wholesale power market in a day, the violator could be subject to $100 million in civil penalties. While no entity has yet been penalized for benefiting from market manipulation, several entities have received penalties under the new authority of FERC to issue civil penalties even where they did not benefit from the violation of FERC rules including Calpine, Cleco, and Bangor Hydro.

Q. Can entities manipulate the market also be subject to joint investigation by FERC and the Commodity Futures Trading Commission?

A. Yes.

Q. Must wholesale power trades be filed with FERC?

A. Yes. Trades must be filed in the EQR data system. They can be reviewed by FERC for exercises in market power.

Q. Has FERC taken steps to alleviate concerns about the quality of index data?

A. Yes. FERC, in consultation with both reporting entities and index publishers, issued a series of guidelines. Index developers were required to adopt and make available a written code of conduct that discloses how the developer will obtain, treat and maintain price data; ensure that price reporting systems maximize the amount of useful and appropriate information that they collect and disseminate; verify price data through various methods, including matching buys and sells and immediately contacting data providers about any discrepancies. In addition, the Commission requested that the index price developers undergo periodic independent audits or verification of processes and index production and provide reasonable access to the price reports in a timely basis to the Commission and the public. Price reporters must provide a clear code of conduct for employees to follow in buying and selling natural gas and electricity and in reporting data to index developers, assign trade data reporting duties to a department that is independent of and not responsible for trading. This is expected of all companies, regardless of size, and report bilateral, arms-length transactions between non-affiliated companies in the physical cash markets by the data providers to index developers in accordance with confidentiality agreements.

Q. Does FERC directly review the market power of market participants?

A. Yes, all entities with greater than 500 MW of capacity must make a triennial filing to ensure that the company continues to satisfy FERC's standards for obtaining or retaining market-based rate authority.

Q. How important is the absence of market power in the context of instituting market-based rates?

A. In order for FERC to grant permission to adopt market-based rates, the wholesale market must be shown to be competitive and free from market power from the entity wanting to participate in the market. In the absence of such a finding, entities can trade at cost-based rates.

Q. Please describe the tests that FERC conducted to measure the degree of market power in TEP's' control area.

A. FERC has established a four-part test to determine whether a utility can adopt market-based retail rates, consisting of generation market power, transmission market power, barriers to entry, and affiliate abuse and/or reciprocal dealing. The failure of one or more of these screens indicates a rebuttable presumption of market power.

Q. How does FERC determine market power in generation?

A. FERC utilizes the Delivered Price Test (DPT) to define the relevant market by identifying potential suppliers based on market prices, input costs, and transmission availability, and calculate each supplier's economic capacity and available economic capacity for each season/load period. The results can be used to conduct pivotal supplier tests, determine market concentration, and measure market share of the supplier. In this context, the DPT is used to conduct the generation market power component of FERC's four-part test for the adoption of market-based retail rates.

Q. What evidence is there that the TEP control area markets are competitive and exhibit low levels of market power?

A. As part of its procedure to determine the allow the adoption of wholesale market-based retail rates, FERC has affirmed in 1997 and again in 2006 that market power is not

present in the TEP region. Most recently, in its Order of Proposed Rulemaking issued July 20, 2006, FERC determined that TEP again passed both the pivotal supplier and wholesale market share screens in each of the directly interconnected first-tier control areas. FERC found that TEP has rebutted the presumption of market power in the TEP control area and satisfied the Commission's generation market power standard for the grant of market-based rate authority.

Q. Has TEP satisfied the other components of the four-part test?

A. Yes. In addition, in both the 1997 and 2006 Orders, the Commission found that Tucson satisfied the Commission's requirements for market-based rates regarding transmission market power, other barriers to entry, and affiliate abuse. As a result, TEP has currently satisfied the full requirements for market-based rates.

Q. Have entities been required to trade using cost-based rates?

A. Yes. Pinnacle West, APS' parent, has been denied market-based rate authority on April 17, 2006 due to failure of the simultaneous transmission import capability study included in the Pinnacle West Companies' filings fails to comply with FERC's directive. As a result, transmission market power portion for 4-part test cannot be conducted, and market-based authority is revoked. Current docket status is that the transmission import study is still under review.

Q. Does FERC regulate mergers and acquisitions of power plants?

A. Yes, under Section 203 of the Federal Power Act, all significant transfers of ownership must be approved by FERC. FERC is the lead agency in power mergers which must meet the standard of being in the public interest. In one recent case, FERC required many thousands of MW of capacity to be divested in order for a merger to take place.

Q. Please additionally describe proposed market structure changes in the California-ISO in response to the 2000 – 2001 events.

A. California is making significant progress in reforming their wholesale power markets in the aftermath of the California power crisis. This reform includes:

- **LMP** – As noted, California is expected to adopt LMP by January 2008.
- **Wholesale Price Caps** – As noted, price caps are approximately $400/MWh in the energy market.
- **Capacity Markets** – As of June 2006, the California market made a significant breakthrough in terms of establishing a capacity requirement with automatic penalties for entities failing to meet state planning reserve requirements. The California Public Utility Commission now mandates that LSEs in the state must contract for resources 15-17% above peak load. California now has an active Resource Adequacy (RA) market, where capacity is traded through bilateral transactions. The RA framework was intended to address reliability at two levels: (1) reliability at the system level, where the focus is on maintaining enough generation capacity to meet total peak system load and reserves, and (2) reliability at the local level, where generation resources need to be in place to meet load and provide reliability services in established transmission-constrained areas.
- **New Transmission Construction** – California has greatly enhanced north south transmission capacity.
- **Retail Cost Pass Through** – Load serving entities do not face price caps and can pass through costs to end users. This reduces the chance of bankruptcy.
- **Litigation** – Significant efforts have been made to settle outstanding disputes related to the 2000 – 2001 energy crisis.

Q. What do you conclude regarding the wholesale marketplace for TEP customers?

A. I conclude that the wholesale power market for TEP customers is robust, very large

compared to the TEP load, and vastly improved since the 2000-2001 crisis. Specifically:

- TEP Load is Relatively Small – The smaller the TEP load, the greater the number of suppliers that can compete to meet this load. TEP load is approximately ten percent of total AZ-NM load, and two percent of total WECC load.
- Market Robustness - FERC has determined that TEP has market based rate authority after reviewing the competitiveness of the market. This is one factor contributing to the conclusion that the wholesale power market is robust. Many of the others are listed below.
- Improvements in the Market Since 2000-2001 – There are several very important improvements in the wholesale markets which contribute to the view they are robust including:
  - By 2010, firm WECC US builds will be 53,000 MW compared to a 2006 summer peak of approximately 131, 000 MW. This supports that the view that the WECC market can respond to meet capacity needs. This is critical since the greatest stress in the market occurs when capacity is short.
  - California has adopted formal resource adequacy rules significantly facilitating capacity expansion, and plans to adopt a Locational Marginal Pricing approach to transmission congestion similar to eastern systems. This system will facilitate market monitoring. In combination, this represents important states to reform the treatment of capacity expansion in a market context.
  - Price caps are still in place for short term transactions, and recent enforcement actions for failure to report on a timely basis emphasize the ongoing importance of these controls. At the same time, longer term transactions have less stringent controls, thereby facilitating the transactions need to support capacity expansion.
  - The Energy Policy Act of 2005 has greatly enhanced the enforcement

authority of FERC, and lead to the creation of an Electric Reliability Organization currently implementing mandatory standards for the entire industry. This eliminates the problems associated with some entities not being subject to FERC regulation, and replaces voluntary standards.

- FERC anti-manipulation rules are very sweeping and are capable of addressing the actions that occurred in the markets in the past.
- The Energy Policy Act of 2005 create a system of extremely strong potential fines, and resolve any uncertainty regarding the authority of FERC to penalize manipulation of other rule violations.
- Anti-manipulation rules supplement FERC Mergers and Acquisition oversight under Section 203, triennial market based rate authority review, and FERC transaction data collection, and rules regarding index reporting.

Q. Does this conclude your prepared testimony?

A. Yes, it does.

EXHIBIT

JLR-1

Exhibit JLR-1
JUDAH L. ROSE

EDUCATION

1982 M.P.P., John F. Kennedy School of Government, **Harvard University**

1979 S.B., Economics, **Massachusetts Institute of Technology**

EXPERIENCE

Judah L. Rose joined ICF in 1982 and currently serves as a Managing Director of ICF International. Mr. Rose has more than 25 years of experience in the energy industry, with emphasis on electric power, generation and transmission. Mr. Rose directs ICF International's wholesale power Line of Business (including assistance to electric utilities, financial institutions, law firms, government agencies, fuel companies, and IPPs). Mr. Rose is one of ICF's Distinguished Consultants, an honorary title given to three of ICF's 1,800 employees, and has served on the Board of Directors of ICF International as the Management Shareholder Representative. Mr. Rose co-manages ICF's IPM© (Integrated Power Model). Mr. Rose has supported the financing of tens of billion dollars of new and existing power plants and is a frequent counselor to the financial community on power issues. Mr. Rose has also served as lead negotiator, and he frequently provides expert testimony and litigation support in power-related court cases. Mr. Rose received a M.P.P. from the John F. Kennedy School of Government, Harvard University, and an S.B. in Economics from the Massachusetts Institute of Technology.

Mr. Rose has publicly testified in scores of state and other legal proceedings, addressed approximately 100 major energy conferences, authored numerous articles published in Public Utilities Fortnightly, the Electricity Journal, Project Finance International, and written numerous company studies on power, coal, and gas related issues, and managed large consulting projects. Mr. Rose has also appeared in TV interviews. Details are provided below.

PRESS INTERVIEWS

TV: "The Most With Allison Stewart," MSNBC, "Blackouts in NY and St. Louis & ongoing
Energy Challenges in the Nation," July 25, 2006
CNBC Wake-Up Call, August 15, 2003
Wall Street Journal Report, July 25, 1999
Back to Business, CNBC, September 7, 1999

Journals: Electricity Journal
Energy Buyer Magazine
Public Utilities Fortnightly
Power Markets Week

Magazine: Business Week
Power Economics
Costco Connection

Newspapers: Denver Post
Rocky Mountain News
Financial Times Energy
LA Times
Arkansas Democratic Gazette
Galveston Daily News
The Times-Picayune
Pittsburgh Post-Gazette
Power Markets Week

Wires: Bridge News
Associated Press
Dow Jones Newswires

TESTIMONY

Portfolio of New Plants, Testimony on behalf of AEP: SWEPCo, before the Arkansas Public Service Commission, In the Matter of Application of SWEPCO for a Certificate of Environmental Compatibility and Public Need for the Construction, Ownership, Operation, and Maintenance of a coal-fired Base Load Generating Facility in the Hempstead County, Arkansas, dated June 2007.

Rebuttal Testimony, Causes No. PUD 200500516, 200600030, and 200700012 Consolidated, on behalf of Redbud Energy, before the Corporation Commission of the State of Oklahoma, June 2007.

IGCC Coal Plant, CPCN Rebuttal Testimony on behalf of Duke Energy Indiana, Cause No. 43114 before the Indiana Utility Regulatory Commission, May 2007.

Rebuttal Testimony, Electric Utility Power Hedging, on behalf of Duke Energy Indiana, Cause No. 38707-FAC6851, May 22, 2007.

Responsive Testimony, Causes No. PUD 200500516, 200600030, and 200700012 Consolidated, on behalf of Redbud Energy, before the Corporation Commission of the State of Oklahoma, May 21, 2007.

Rebuttal Testimony, FPL – CO_2 Emissions, Docket No. 070098-EL, March 30, 2007

Electric Utility Power Hedging, on behalf of Duke Energy Indiana, Cause No. 38707-FAC6851, February 9, 2007.

CPCN for Cliffside Coal Plant, on behalf of Duke Carolinas, Docket No. E7, SUB790, December 2006.

Confidential Expert Report, Nuclear Power Siting, December 2006, South Carolina.

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Expert Report, Chapter 11, Case No. 01-16034 (AJG) and Adv. Proc. No. 04-2933 (AJG), November 6, 2006.

Market Power and the PSEG Exelon Merger on Behalf of the NJBPU Staff, NJBPU, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-05, Supplemental Testimony March 20, 2006.

Market Power and the PSEG Exelon Merger on Behalf of the NJBPU Staff, NJBPU, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-05, Surrebuttal Testimony December 27, 2005.

Market Power and the PSEG Exelon Merger on Behalf of the NJBPU Staff, NJBPU, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-05, November 14, 2005.

Brazilian Power Purchase Agreement, confidential international arbitration, October 2005.

Cost of Service and Fuel Clause Issues, Rebuttal Testimony on behalf of Public Service of New Mexico, Docket No. EL05-151, November 2005.

Cost of Service and Peak Demand, FERC, Testimony on behalf of Public Service of New Mexico, September 19, 2005, Docket No. EL05-19.

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New Air Emission Regulations and Investment in Coal Power Plants, rebuttal testimony on behalf of PSI, April 18, 2005, Causes 42622 and 42718.

Rebuttal Report: Damages due to Rejection of Tolling Agreement Including Discounting, February 9, 2005, CONFIDENTIAL.

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Discount rates that should be used in estimating the damages to GTN of Mirant's bankruptcy and subsequent abrogation of the gas transportation agreements Mirant had entered into with GTN, December 15, 2004. CONFIDENTIAL

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Rebuttal Testimony of Judah Rose on behalf of the Hopi Tribe, Case No. A.02-05-046, June 4, 2004.

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"Application of Southern California Edison Company (U338-E) Regarding the Future Disposition of the Mohave Generating Station," May 14, 2004.

"Appropriate Rate of Return on Equity (ROE) TransAlta Should be Authorized For its Capital Investment Related to VAR Support From the Centralia

Coal-Fired Power Plant", for TransAlta, April 30, 2004, FERC Docket No. ER04-810-000.

"Retail Generation Rates, Cost Recovery Associated with the Midwest Independent Transmission System Operator, Accounting Procedures for Transmission and Distribution System, Case No. 03-93-EL-ATA, 03-2079, EL-AAM, 03-2081, EL-AAM, 03-2080, EL-ATA for Cincinnati Gas & Electric, April 15, 2004.

"Application of Southern California Edison Company (U338-E) Regarding the Future Disposition of the Mohave Generating Station," May 14, 2004.

"Appropriate rate of return on equity (ROE) TransAlta should be authorized for its capital investment related to VAR support from the Centralia coal-fired power plant", for TransAlta, April 30, 2004.

"Retail Generation Rates, Cost Recovery Associated with the Midwest Independent Transmission System Operator, Accounting Procedures for Transmission and Distribution System, Case No. 03-93-EL-ATA, 03-2079, EL-AAM, 03-2081, EL-AAM, 03-2080, EL-ATA for Cincinnati Gas & Electric, April 15, 2004.

"Valuation of Selected MIRMA Coal Plants, Acceptance and Rejection of Leases and Potential Prejudice to Leasors" Federal Bankruptcy Court, Dallas, TX, March 24, 2004 CONFIDENTIAL.

"Certificate of Purchase as of yet Undetermined Generation Facility", Cause No. 42469 for PSI, March 23, 2004.

"Ohio Edison's Sammis Power Plant BACT Remedy Case", In the United States District Court of Ohio, Southern Division, March 8, 2004.

"Valuation of Power Contract," January 2004, confidential arbitration.

"In the matter of the Application of the Union Light Heat & Power Company for a Certificate of Public Convenience and Necessity to Acquire Certain Generation Resources, etc.", before the Kentucky Public Service Commission, July 21, 2003.

"In the Supreme Court of British Columbia", July 8, 2003. CONFIDENTIAL

"The Future of the Mohave Power Plant – Rebuttal Testimony", California P.U.C., May 20, 2003.

"Affidavit in Support of the Debtors' Motion", NRG Bankruptcy, May 14, 2003. CONFIDENTIAL

"IPP Power Purchase Agreement," confidential arbitration, April 2003.

"The Future of the Mohave Power Plant", California P.U.C., March 2003.

"Power Supply in the Pacific Northwest," contract arbitration, December 5, 2002. CONFIDENTIAL

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"Cause No. 42145 - rebuttal testimony on behalf of PSI. Filed on 8/23/02."

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"Cause No. 42196 - in support of PSI's petition for interim purchased power contract. Filed on 4/26/02."

"Cause No. 42145 - in support of PSI's petition for authority to acquire the Madison and Henry County plants. Filed on 3/1/2002."

"Analysis of an IGCC Coal Power Plant", Minnesota state senate committees, January 22, 2002

"Analysis of an IGCC Coal Power Plant", Minnesota state house of representative committees, January 15, 2002

"Interim Pricing Report on New York State's Independent System Operator", New York State Public Service Commission (NYSPSC), January 5, 2001

" The need for new capacity in Indiana and the IRP process", Indiana Utility Regulatory Commission, October 26, 2000

"Damage estimates for power curtailment for a Cogen power plant in Nevada", August 2000. CONFIDENTIAL

"Valuation of a power plant in Arizona", arbitration, July 2000. CONFIDENTIAL

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"Wholesale Power Prices, A Cost Plus All Requirements Contract and Damages", July 1999. Testimony to U.S. Bankruptcy Court.

"Power Prices." Testimony in confidential contract arbitration, July 1998.

"Horizontal Market Power in Generation." Testimony to New Jersey Board of Public Utilities, May 22, 1998.

"Basic Generation Services and Determining Market Prices." Testimony to the New Jersey Board of Public Utilities, May 12, 1998.

"Generation Reliability." Testimony to New Jersey Board of Public Utilities, May 4, 1998.

"Future Rate Paths and Financial Feasibility of Project Financing." Testimony to U.S. Bankruptcy Court, April 1998.

"Stranded Costs of PSE&G." Testimony to New Jersey Board of Public Utilities, February 1998.

"Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code." Rebuttal Testimony filed July 1997.

"Future Wholesale Electricity Prices, Fuel Markets, Coal Transportation and the Cajun Bankruptcy." Testimony to Louisiana Public Service Commission, December 1996.

"Curtailment of the Saguaro QF, Power Contracting and Southwest Power Markets." Testimony on a contract arbitration, Las Vegas, Nevada, June 1996.

"Future Rate Paths and the Cajun Bankruptcy." Testimony to the U.S. Bankruptcy Court, June 1997.

"Fuel Prices and Coal Transportation." Testimony to the U.S. Bankruptcy Court, June 1997.

"Demand for Gas Pipeline Capacity in Florida from Electric Utilities." Testimony to Florida Public Service Commission, May 1993.

"The Case for Fuel Flexibility in the Florida Electric Generation Industry." Testimony to the Florida Department of Environmental Regulation (DER), Hearings on Fuel Diversity and Environmental Protection, December 1992.

SELECTED SPEAKING ENGAGEMENTS

Rose, J.L., AESP, NEEC Conference, Rising Prices and Failing Infrastructure: A Bleak or Optimistic Future, Marlborough, MA, October 23, 2006.

Rose, J.L., Infocast Gas Storage Conference, "Estimating the Growth Potential for Gas-Fired Electric Generation," Houston, TX, March 22, 2006.

Rose, J.L., "Power Market Trends Impacting the Value of Power Assets," Infocast Conference, Powering Up for a New Era of Power Generation M&A, February 23, 2006.

Rose, J.L., "The Challenge Posed by Rising Fuel and Power Costs", Lehman Brothers, November 2, 2005.

Rose, J.L., "Modeling the Vulnerability of the Power Sector", EUCI – Securing the Nation's Energy Infrastructure, September 19, 2005

Rose, J.L., "Fuel Diversity in the Northeast, Energy Bar Association, Northeast Chapter Meeting, New York, NY, June 9, 2005.

Rose, J.L., "2005 Macquarie Utility Sector Conference", Macquarie Utility Sector Conference, Vail, CO, February 28, 2005.

Rose, J.L., "The Outlook for North American Natural Gas and Power Markets", The Institute for Energy Law, Program on Oil and Gas Law, Houston, TX, February 18, 2005.

Rose, J.L. "Assessing the Salability of Merchant Assets – What's on the Horizon?", Infocast – The Market for Power Assets, Phoenix, AZ, February 10, 2005.

Rose, J.L. "Market Based Approaches to Transmission – Longer-Term Role", National Group of Municipal Bond Investors, New York, NY, December 10, 2004.

Rose, J.L. "Supply & Demand Fundamentals – What is Short-Term Outlook and the Long-Term Demand? Platt's Power Marketing Conference, Houston, TX, October 11, 2004.

Rose, J.L. "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?, Infocast's Buying, Selling, and Investing in Energy Assets Conference, Houston, TX, June 24, 2004.

Rose, J. L. "After the Blackout – Questions That Every Regulator Should be Asking," NARUC Webinar Conference, Fairfax, VA, November 6, 2003.

Rose, J. L., "Supply and Demand in U.S. Wholesale Power Markets," Lehman Brothers Global Credit Conference, New York, NY, November 5, 2003.

Rose, J.L., "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?", Infocast's Opportunities in Energy Asset Acquisition, San Francisco, CA, October 9, 2003.

Rose, J.L., "Asset Valuation in Today's Market", Infocast's Project Finance Tutorial, New York, NY, October 8, 2003.

Rose, J.L., "Forensic Evaluation of Problem Projects", Infocast's Project Finance Workouts: Dealing With Distressed Energy Projects, September 17, 2003.

Rose, J.L., National Management Emergency Association, Seattle, WA, September 8, 2003.

Rose, J.L., "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?", Infocast's Buying, Selling & Investing in Energy Assets, Chicago, IL, July 24, 2003.

Rose, J.L., CSFB Leveraged Finance Independent Power Producers and Utilities Conference, New York, NY, "Spark Spread Outlook", July 17, 2003.

Rose, J.L., Multi-Housing Laundry Association, Washington, D. C., "Trends in U.S. Energy and Economy", June 24, 2003.

Rose, J.L., "Power Markets: Prices, SMD, Transmission Access, and Trading", Bechtel Management Seminar, Frederick, MD, June 10, 2003.

Rose, J.L., Platt's Global Power Market Conference, New Orleans, LA, "The Outlook for Recovery," March 31, 2003.

Rose, J.L., "Electricity Transmission and Grid Security", Energy Security Conference, Crystal City, VA, March 25, 2003.

Rose, J.L., "Assessing the Salability of Merchant Assets – When Will We Hit Bottom?, Infocast's Buying, Selling & Investing in Energy Assets, New York City, February 27, 2003.

Rose, J.L., Panel Discussion, "Forensic Evaluation of Problem Projects", Infocast Conference, NY, February 24, 2003.

Rose, J.L., PSEG Off-Site Meeting Panel Discussion, February 6, 2003 (April 13, 2003).

Rose, J.L., "The Merchant Power Market—Where Do We Go From Here?" Center for Business Intelligence's Financing U.S. Power Projects, November 18-19, 2002.

Rose, J.L., "Assessing U.S. Regional And The Potential for Additional Coal-Fired Generation in Each Region," Infocast's Building New Coal-Fired Generation Conference, October 8, 2002.

Rose, J.L., "Predicting the Price of Power for Asset Valuation in the Merchant Power Financings, "Infocast's Product Structuring in the Real World Conference, September 25, 2002.

Rose, J.L., "PJM Price Outlook," Platt's Annual PJM Regional Conference, September 24, 2002.

Rose, J.L., "Why Investors Are Zeroing in on Upgrading Our Antiquated Power Grid Rather Than Exotic & Complicated Technologies," New York Venture Group's Investing in the Power Industry—Targeting The Newest Trends Conference, July 31, 2002.

Rose, J.L., Panel Participant in the Salomon Smith Barney Power and Energy Merchant Conference 2002, May 15, 2002.

Rose, J.L., "Locational Market Price (LMP) Forecasting in Plant Financing Decisions," Structured Finance Institute, April 8-9, 2002.

Rose, J.L., "PJM Transmission and Generation Forecast", Financial Times Energy Conference, November 6, 2001.

Rose, J.L., "U.S. Power Sector Trends", Credit Suisse First Boston's Power Generation Supply Chain Conference, Web Presented Conference, September 12, 2002.

Rose, J.L., "Dealing with Inter-Regional Power Transmission Issues", Infocast's Ohio Power Game Conference, September 6, 2001

Rose, J.L., "Where's the Next California", Credit Suisse First Boston's Global Project Finance Capital Markets Conference, New York NY, June 27 2001

Rose, J.L, "U.S. Energy Issues: What MLA Members Need to Know," Multi-housing Laundry Association, Boca Raton Florida, June 25, 2001

Rose, J.L., "How the California Meltdown Affects Power Development", Infocast's Power Development and Finance Conference 2001, Washington D.C., June 12, 2001

Rose, J.L., "Forecasting 2001 Electricity Prices" presentation and workshop, What to Expect in western Power Markets this Summer 2001 Conference, Denver, Colorado, May 2, 2001

Rose, J.L., "Power Crisis in the West" Generation Panel Presentation, San Diego, California, February 12, 2001

Rose, J.L., " An Analysis of the Causes leading to the Summer Price Spikes of 1999 & 2000" Conference Chair, Infocast Managing Summer Price Volatility, Houston, Texas, January 30, 2001.

Rose, J. L., " An Analysis of the Power Markets, summer 2000" Generation Panel Presentation, Financial Times Power Mart 2000 conference, Houston, Texas, October 18, 2000

Rose, J.L., "An Analysis of the Merchant Power Market, Summer 2000" presentation, Conference Chair, Merchant Power Finance Conference, Atlanta, Georgia, September 11 to 15, 2000

Rose, J.L., "Understanding Capacity Value and Pricing Firmness" presentation, Conference Chair, Merchant Plant Development and Finance Conference, Houston, Texas, March 30, 2000.

Rose, J.L., "Implementing NYPP's Congestion Pricing and Transmission Congestion Contract (TCC)", Infocast Congestion Pricing and Forecasting Conference, Washington D.C., November 19, 1999.

Rose, J.L., "Understanding Generation" Pre-Conference Workshop, Powermart, Houston, Texas, October 26-28, 1999.

Rose, J.L., "Understanding Capacity Value and Pricing Firmness" presentation, Conference Chair Merchant Plant Development and Finance Conference, Houston, Texas, September 29, 1999.

Rose, J.L., "Comparative Market Outlook for Merchant Assets" presentation, Merchant Power Conference, New York, New York, September 24, 1999.

Rose, J.L., "Transmission, Congestion, and Capacity Pricing" presentation, Transmission The Future of Electric Transmission Conference, Washington, DC, September 13, 1999.

Rose, J.L., "Effects of Market Power on Power Prices in Competitive Energy Markets" Keynote Address, The Impact of Market Power in Competitive Energy Markets Conference, Washington, DC, July 14, 1999.

Rose, J.L., "Peak Price Volatility in ECAR and the Midwest, Futures Contracts: Liquidity, Arbitrage Opportunity" presentation at ECAR Power Markets Conference, Columbus, Ohio, June 9, 1999.

Rose, J.L., "Transmission Solutions to Market Power" presentation, Do Companies in the Energy Industry Have Too Much Market Power? Conference, Washington, DC, May 24, 1999.

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EMPLOYMENT HISTORY

ICF Resources Incorporated	Managing Director	1999-Present
	Vice President	1996-1999
	Project Manager	1993-1996
	Senior Associate	1986-1993
	Associate	1982-1986

EXHIBIT

JLR-2

<CONFIDENTIAL>
Exhibit JLR-2
Natural Gas Price Forecast, 2007-2036, 2006$/MMbtu

EXHIBIT

JLR-3

<CONFIDENTIAL>
Exhibit JLR-3
Forecast Minemouth PRB Coal Prices, $/ton, 2007-2036

EXHIBIT

JLR-4

Exhibit JLR-4
Firmly Planned and Recently Completed Plants in Arizona-New Mexico-Southern Nevada

Plant Name	Capacity Type	Net Dependable Capacity (MW)	Online Date	IPM Model Region
Springerville Generating Station	Solar	1.1	4/1/2005	ARIZONA
Santan	CC	550	4/20/2005	ARIZONA
Bluffview	CC	65	6/16/2005	N. NEW MEXICO
Prescott Airport Solar Plant	Solar	1	7/26/2005	ARIZONA
Palo Verde	Nuclear	71	12/23/2005	ARIZONA
Saguaro	Solar	1	12/27/2005	ARIZONA
2005 Sub-Total		**689**		
Santan	CC	275	3/1/2006	ARIZONA
Prescott Airport Solar Plant	Solar	1	3/2/2006	ARIZONA
Luna Energy Facility	CC	562	4/4/2006	S. NEW MEXICO
Valencia	Gas Turbine	20	6/6/2006	ARIZONA
Springerville Generating Station	Coal	418	7/28/2006	ARIZONA
Argonne Mesa	Wind	18	12/22/2006	N. NEW MEXICO
2006 Sub-Total		**1,294**		
Los Alamos Unit	Gas Turbine	25	4/30/2007	N. NEW MEXICO
Afton Generating Station	CC	95	5/31/2007	S. NEW MEXICO
Palo Verde	Nuclear	71	12/31/2007	WECC/CAISO
Snowflake White Mountain Power	Biomass	24	12/31/2007	ARIZONA
2007 Sub-Total		**215**		
Springerville Generating Station	Coal	400	12/31/2009	ARIZONA
Grand Total		**2,598**		

EXHIBITS

JLR-5 and JLR-6

<CONFIDENTIAL>
Exhibit JLR-5
Unplanned Fossil and Nuclear Unit Power Plant Capital Costs, 2007-2036, 2006$/kW

<CONFIDENTIAL>
Exhibit JLR-6
Unplanned Renewable Unit Capital Costs, 2007-2036, 2006$/kW

EXHIBITS

JLR-7 and JLR-8

<CONFIDENTIAL>
Exhibit JLR-7
Unplanned Power Plant Full Load Heat Rate (Btu/kWh)

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Exhibit JLR-8
Unplanned Power Plant Non-Fuel Variable O&M Costs, 2006$/MWh

<CONFIDENTIAL> Unplanned Power Plant Fixed O&M Costs, 2006$/kW-yr

EXHIBIT

JLR-9

<CONFIDENTIAL>
Exhibit JLR-9
Emission Allowance Price Forecasts, 2006-2036, 2006$

EXHIBIT

JLR-10

<CONFIDENTIAL>

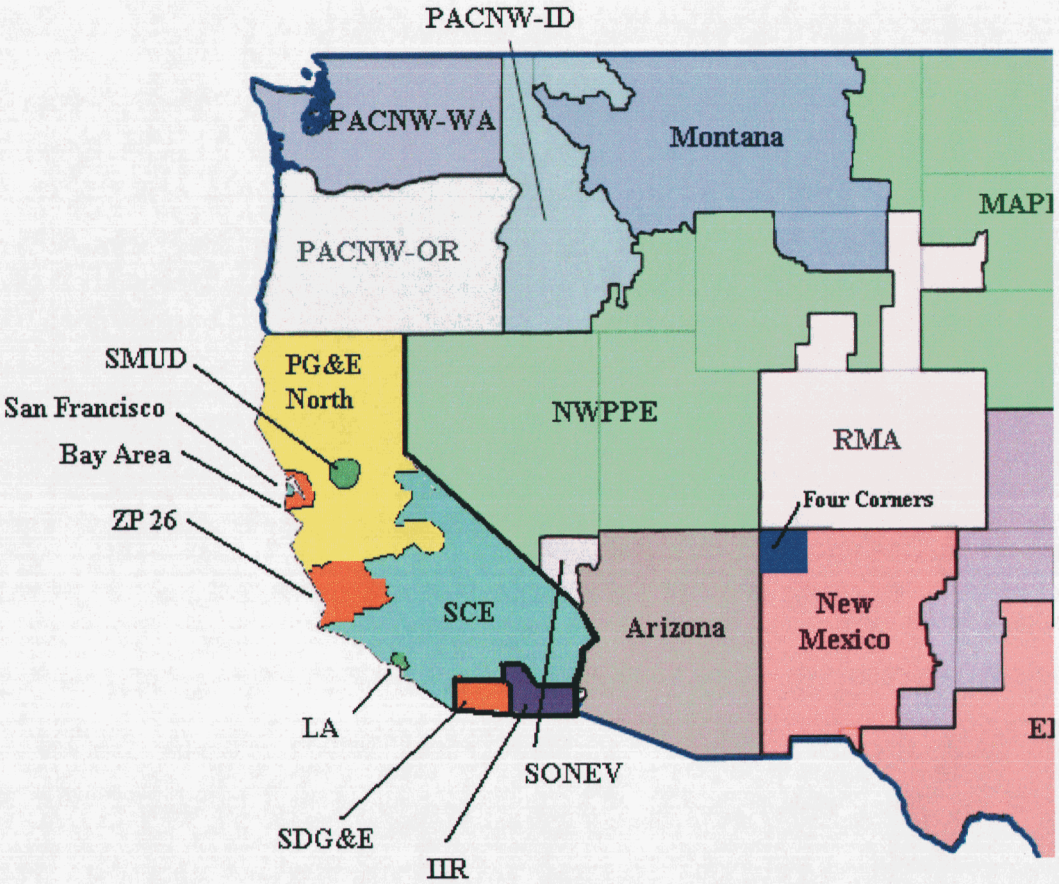
Exhibit JLR-10

WECC Peak and Energy Demand Forecast, 2007-2036, Arizona and New Mexico

EXHIBIT

JLR-11

Exhibit JLR-11
ICF IPM® WECC Model Regions



EXHIBIT

JLR-12

Exhibit JLR-12
TEP Plant Details

Unit	ICF Model Region	Heat Rate[1] (Btu/kWh)	TEP Capacity Share (MW)	FOM, 2006$/ kW-yr[1]	VOM, 2006$/MWh[1]
Four Corners-4	Four Corners / San Juan	9,810	55	45	1.01
Four Corners-5	Four Corners / San Juan	9,790	55	45	1.01
Navajo-1	Arizona	10,289	56	42	1.12
Navajo-2	Arizona	10,105	56	42	1.12
Navajo-3	Arizona	10,221	56	42	1.12
San Juan-1	Four Corners / San Juan	9,235	164	46	1.71
San Juan-2	Four Corners / San Juan	10,355	158	46	1.71
Springerville 2	Arizona	10,039	380	30	1.30
Sundt 1	Arizona	11,546	81	18	0.57
Sundt 2	Arizona	12,128	81	18	0.57
Sundt 3	Arizona	13,232	104	18	0.57
Luna Electric 1	New Mexico	7,088	145	26	0.90
Sundt CT	Arizona	15,038	54	21	0.63
North Loop 1-4	Arizona	14,180	122	21	0.63
DeMoss Petrie Unit	Arizona	11,100	95	21	0.63

Source: ICF International
[1]Average of 2007-2036

EXHIBITS

JLR-13 and JLR-14

Exhibit JLR-13
Financing Assumptions used in ICF IPM Analysis

Input	Gas CC	Gas CT	Coal & Nuclear	Wind & Renew
Book Life (years)	30	30	40	20
Debt Life (years)	20	15	20	20
MACRS Depreciation Schedule (years)	20	15	20	5
After Tax Nominal Equity Rate (%)	13%	13%	13%	13%
Equity Ratio (%)	55%	70%	40%	55%
Pre-Tax Nominal Debt Rate (%)	8%	9%	8%	8%
Debt Ratio (%)	45%	30%	60%	45%
Income Tax Rate (%)	40.30%	40.3%	40.3%	40.3%
Other Taxes/Insurance (%)	1.04%	1.04%	1.04%	1.04%
Inflation (%)	2.50%	2.50%	2.50%	2.50%
Outputs				
Levelized Real Fixed Capital Charge Rate (%)	12.46%	13.68%	10.82%	10.85%
Nominal Weighted Average Cost of Capital (WACC) (%)	9.30%	10.71%	8.07%	9.30%
Real WACC (%)	6.63%	8.01%	5.43%	6.63%

Exhibit JLR-14
Summary of Valuation Results

Technology	TEP Capacity Share (MW)	Value (B$)
Coal Units	980	2.634
Combined Cycle Units	187	0.114
Combustion Turbines	217	0.082
Total	1,384	2.830

EXHIBIT

JLR-15

Exhibit JLR-15
Results - Coal Plants

Unit	ICF Model Region	Heat Rate (Btu/kWh)	Capacity Factor (%)	TEP Capacity Share (MW)	Value (2006MM$)[2]	Value (2006$/kW)[2]
Four Corners 4	Four Corners/ San Juan	9,810	83	55	[redacted]	[redacted]
Four Corners 5	Four Corners/ San Juan	9,790	84	55	[redacted]	[redacted]
Navajo 1	Arizona	10,289	91	56	[redacted]	[redacted]
Navajo 2	Arizona	10,105	90	56	[redacted]	[redacted]
Navajo 3	Arizona	10,221	91	56	[redacted]	[redacted]
San Juan 1	Four Corners/ San Juan	9,235	86	164	[redacted]	[redacted]
San Juan 2	Four Corners/ San Juan	10,407	84.2	158	[redacted]	[redacted]
Springerville	Arizona	10,039	91	380	[redacted]	[redacted]
Average/Total[1]		9987	88	980	2,634	2,689

[1] Simple average
[2] Discounted to 1/1/2007 in 2006$

Results - Combined Cycle

Unit	ICF Model Region	Heat Rate (Btu/kWh)	Capacity Factor (%)	TEP Capacity Share (MW)	Value (2006MM$)[2]	Value (2006$/kW)[1]
Luna CC (with Duct Firing)	New Mexico	7,222	26	187	114	611

[1] Discounted to 1/1/2007 in 2006$
[2] Average heat rate for Luna combined cycle and duct-firing unit shown.

Results - Combustion Turbines

Unit	ICF Model Region	Heat Rate (Btu/kWh)	Capacity Factor (%)	TEP Capacity Share (MW)	Value ($2006MM)[2]	Value ($2006/kW)[2]
North Loop CT 1-3	Arizona	15,135	1.7	73	27.9	382
North Loop CT 4	Arizona	11,317	5.5	21	5.3	257
DeMoss	Arizona	11,100	5.6	75	30.2	403
Sundt CT	Arizona	15,038	1.9	48	18.2	376
Average Total[1]		13148	3.7	217	82	376

[1] Simple average
[2] Discounted to 1/1/2007 in 2006$
Note: Discounted to 1/1/2007.
Source: ICF International

EXHIBIT

JLR-16

<CONFIDENTIAL>
Exhibit JLR-16
Arizona Energy, Capacity, and Firm Power Prices, 2007-2036, 2006$

<CONFIDENTIAL> Arizona Energy, Capacity, and Firm Power Prices, 2007-2036, Nominal$

EXHIBITS

JLR-17 and JLR-18

Exhibit JLR-17
Peak and Energy Demand Historical Growth Rate, 1994-2005, Arizona, New Mexico, and Southern Nevada

	Peak Demand	Net Energy Sales
1994-2005 AAGR	4.57%	3.57%

Source: 2006 WECC 10-Year Coordinated Plan Summary

Exhibit JLR-18
Peak and Energy Demand Forecast, 2007-2015, Arizona, New Mexico, and Southern Nevada

	Peak Demand	Net Energy Demand
Annual Average Growth Rate (2006-2015)	2.91%	2.85%

Source: NERC ES&D 2006

EXHIBIT

JLR-19

<CONFIDENTIAL>
Exhibit JLR-19
Unplanned and Firmly Planned Builds, 2007-2036, MW

EXHIBIT

JLR-20

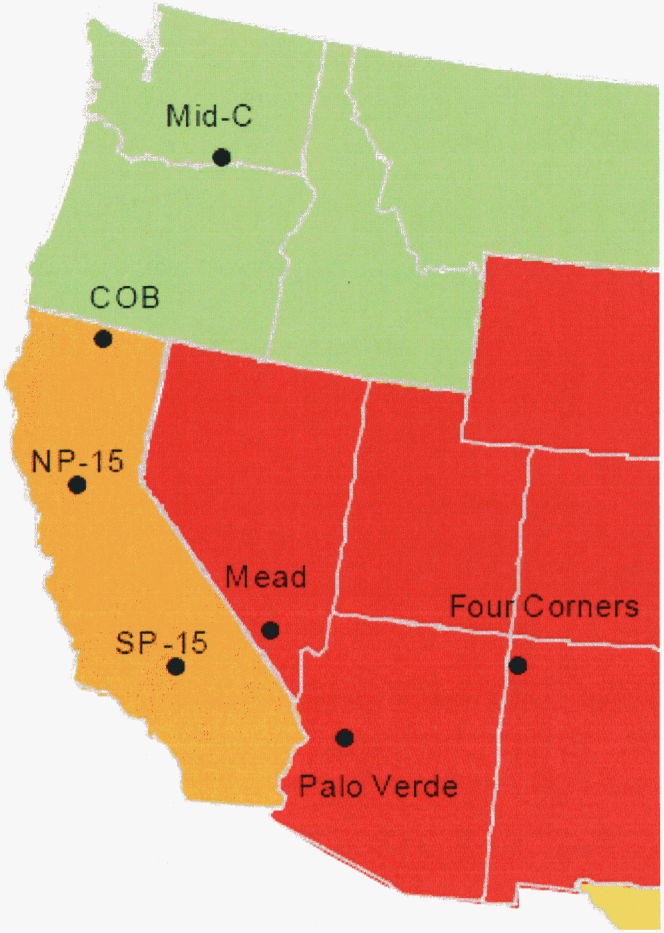
<CONFIDENTIAL>
Exhibit JLR-20
Capacity Price Forecast – Base Case

EXHIBIT

JLR-21

Exhibit JLR-21

Western US Trading Hubs



SOURCE: FERC

EXHIBIT

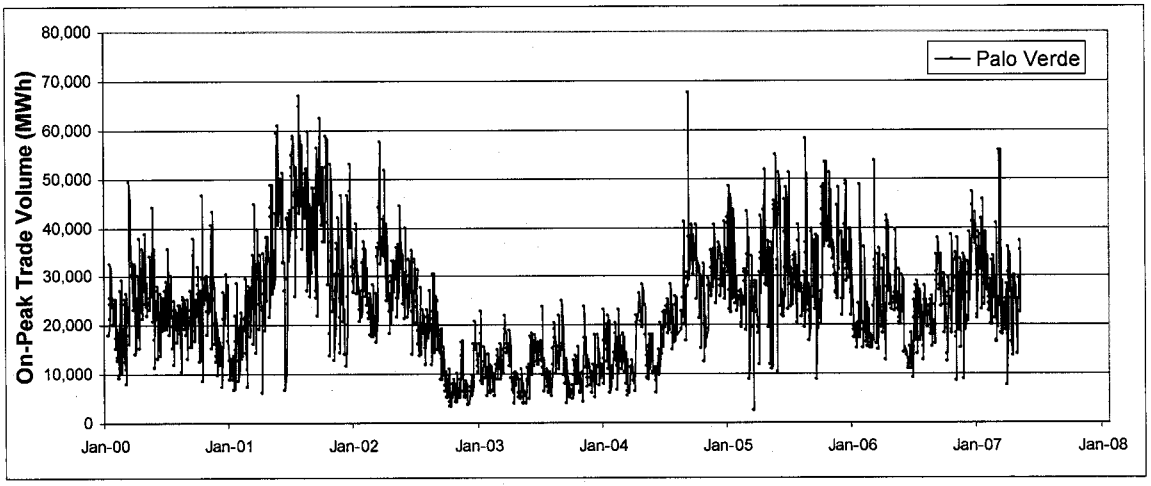
JLR-22

Exhibit JLR-22
Historical Volume, 1996-2006, MWh

Year	PALO VERDE			FOUR CORNERS			SP-15		
	Peak	Off Peak	All Hours	Peak	Off Peak	All Hours	Peak	Off Peak	All Hours
2000	22,886	1,878	13,874	2,901	763	1,983	10,688	1,438	6,720
2001	32,515	8,133	22,055	2,472	1,037	1,856	19,342	5,126	13,243
2002	22,905	4,998	15,223	3,107	1,413	2,380	21,016	6,082	14,609
2003	11,231	3,077	7,733	4,844	1,673	3,484	26,954	7,148	18,457
2004	19,420	6,573	13,909	31,744	2,430	19,169	215,395	12,204	128,226
2005	31,210	8,331	21,395	6,738	2,695	5,004	96,217	22,771	64,709
2006	24,298	6,678	16,739	7,735	3,465	5,903	106,280	19,730	69,150
2007	29,021	5,114	18,765	6,116	3,244	4,884	112,590	24,918	74,978
2000-2006 Average	24,186	5,598	16,212	8,207	2,090	5,583	76,060	12,427	48,762

Year	NP-15			COB			Mid-Columbia		
	Peak	Off Peak	All Hours	Peak	Off Peak	All Hours	Peak	Off Peak	All Hours
2000	6,748	3,161	5,209	-	-	-	10,308	1,595	6,570
2001	15,957	6,271	11,802	3,416	994	2,377	12,046	3,286	8,288
2002	21,792	5,828	14,943	8,257	3,222	6,097	25,850	6,855	17,701
2003	20,204	5,691	13,978	5,693	2,347	4,258	19,499	8,264	14,679
2004	115,784	9,388	70,140	53,551	4,675	32,584	169,450	8,893	100,571
2005	31,815	11,723	23,195	10,362	3,534	7,433	51,486	19,999	37,978
2006	30,159	14,244	23,332	9,407	4,199	7,173	73,842	22,044	51,620
2007	48,735	16,576	34,939	11,210	4,658	8,399	104,919	27,243	71,596
2000-2006 Average	36,399	9,110	24,692	14,557	3,376	9,760	58,425	12,272	38,625

Exhibit JLR-22a
Palo Verde On-Peak Trade Volume 2001 - June 2007 (MWh)



Source: MW Daily

EXHIBIT

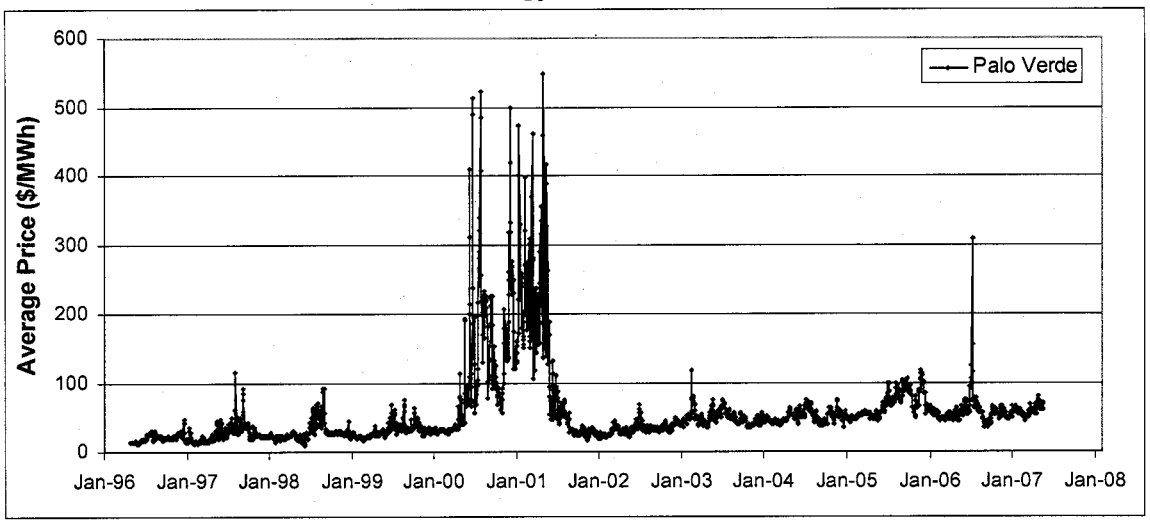
JLR-23

Exhibit JLR-23
Average Annual Prices, $/MWh, 1996-2006

Year	PALO VERDE			FOUR CORNERS			SP-15		
	Peak	Off Peak	All Hours	Peak	Off Peak	All Hours	Peak	Off Peak	All Hours
1996	21.1	-	-	-	-	-	-	-	-
1997	26.5	12.3	20.4	27.4	12.5	21.0	-	-	-
1998	29.3	14.8	23.1	28.1	13.9	22.0	-	-	-
1999	31.3	18.0	25.6	30.4	16.2	24.3	32.7	17.4	26.1
2000	115.6	54.5	89.4	116.1	51.6	88.4	112.2	73.5	95.6
2001	122.5	60.6	96.0	118.8	60.4	93.7	120.2	71.3	99.2
2002	32.7	19.6	27.0	32.9	19.6	27.2	34.1	21.7	28.8
2003	49.0	32.8	42.1	48.6	32.3	41.6	51.3	35.1	44.4
2004	50.6	37.4	44.9	51.0	37.4	45.2	55.5	41.4	49.4
2005	67.4	51.5	60.5	69.4	51.3	61.6	73.1	56.0	65.7
2006	57.7	38.2	49.3	58.6	37.9	49.7	61.9	41.5	53.2
2007	58.2	42.2	51.3	58.6	41.0	51.1	63.2	46.9	56.2
1996-2006 Average	55.2	34.7	48.2	58.2	34.0	47.8	67.1	45.0	57.6

Year	NP-15			COB			Mid-Columbia		
	Peak	Off Peak	All Hours	Peak	Off Peak	All Hours	Peak	Off Peak	All Hours
1996	-	-	-	-	-	-	15.5	-	-
1997	-	-	-	-	-	-	15.9	11.6	14.0
1998	-	-	-	27.5	17.5	23.2	26.2	18.5	22.9
1999	35.7	19.9	29.0	30.7	19.4	25.9	26.6	18.1	22.9
2000	115.4	84.3	102.1	137.3	70.0	108.5	138.9	83.3	115.0
2001	134.3	95.4	117.6	142.9	96.6	123.1	142.9	108.5	128.1
2002	33.1	22.6	28.6	28.6	21.0	25.3	23.9	20.0	22.3
2003	49.0	35.7	43.3	44.4	35.1	40.4	40.6	34.0	37.8
2004	54.7	43.0	49.7	49.2	41.6	45.9	44.4	38.3	41.8
2005	72.5	56.0	65.4	67.0	55.5	62.1	63.0	53.6	59.0
2006	61.1	40.7	52.3	55.6	40.6	49.1	50.2	38.5	45.2
2007	63.3	47.1	56.3	56.6	44.4	51.3	50.3	39.9	45.8
1996-2006 Average	68.8	49.4	60.5	64.0	44.2	55.5	53.2	42.2	50.4

Exhibit JLR-23a
Palo Verde On-Peak Energy Prices 1997 - June 2007 (MWh)



Source: MW Daily

EXHIBIT

JLR-24

<CONFIDENTIAL>
EXHIBIT JLR-24
Total WECC Firm Builds (1999-2010) Current Nameplate Capacity & Planned Capacity (MW)

<CONFIDENTIAL>
EXHIBIT JLR-24
Total WECC Firm Builds (1999-2010) Current Nameplate Capacity & Planned Capacity (MW)
CONTINUED

Direct Testimony of Dr. Samuel C. Hadaway

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
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.	DOCKET NO E-01933A-07-

Direct Testimony of

Samuel C. Hadaway, Ph. D.

on Behalf of

Tucson Electric Power Company

July 2, 2007

TABLE OF CONTENTS

I. Introduction and Qualifications 1

II. Purpose and Summary of Testimony 2

III. Structural Organization and Operating Characteristics of TEP 6

IV. Estimating the Cost of Equity Capital 9

V. Fundamental Factors That Affect the Cost of Equity 21

VI. Cost of Equity Capital for TEP 28

Exhibits:

Exhibit SCH-1	Non-Investment Grade Spread Analysis
Exhibit SCH-2	Comparable Company Capital Structures and Fundamental Characteristics
Exhibit SCH-3	Capital Spending Relative to Net Plant
Exhibit SCH-4	Historical Capital Market Costs
Exhibit SCH-5	Comparison of Analysts' Growth Rates
Exhibit SCH-6	GDP Growth Rate Forecast
Exhibit SCH-7	Discounted Cash Flow Analysis
Exhibit SCH-8	Capital Asset Pricing Model Analysis
Exhibit SCH-9	Risk Premium Analysis

I. INTRODUCTION AND QUALIFICATIONS.

Q. Please state your name, occupation, and business address.

A. My name is Samuel C. Hadaway. I am a Principal in FINANCO, Inc., Financial Analysis Consultants, 3520 Executive Center Drive, Austin, Texas 78731.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Tucson Electric Power Company (hereinafter "TEP" or the Company).

Q. Please state your educational background and describe your professional training and experience.

A. I have a Bachelor's degree in economics from Southern Methodist University, as well as MBA and Ph.D. degrees with concentrations in finance and economics from the University of Texas at Austin ("UT Austin"). For more than 20 years, I have been an owner and full-time employee of FINANCO, Inc. FINANCO provides financial research concerning the cost of capital and financial condition for regulated companies as well as financial modeling and other economic studies in litigation support. In addition to my work at FINANCO, I have served as an adjunct professor in the McCombs School of Business at UT Austin and in what is now the McCoy College of Business at Texas State University. In my prior academic work, I taught economics and finance courses and I conducted research and directed graduate students in the areas of investments and capital market research. I was previously Director of the Economic Research Division at the Public Utility Commission of Texas where I supervised the Commission's finance, economics, and accounting staff, and served as the Commission's chief financial witness in electric and telephone rate cases. I have taught courses at various utility conferences on cost of capital, capital structure, utility financial condition, and cost allocation and rate

design issues. I have made presentations before the New York Society of Security Analysts, the National Rate of Return Analysts Forum, and various other professional and legislative groups. I have served as a vice president and on the board of directors of the Financial Management Association. A list of my publications and testimony I have given before various regulatory bodies and in state and federal courts is contained in my resume, which is attached as Appendix A.

II. PURPOSE AND SUMMARY OF TESTIMONY.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to estimate TEP's market required rate of return on equity ("ROE") and to support the Company's requested capital structure and overall rate of return.

Q. Please outline and describe the testimony you will present.

A. My testimony is divided into four additional sections. Following this introduction, I describe TEP's organizational structure and fundamental risk characteristics. In the following section, I review various methods for estimating the cost of equity. In that section, I discuss comparable earnings methods, risk premium methods, and discounted cash flow (DCF) methods. In the following section, I review general capital market costs and conditions and discuss recent developments in the electric utility industry that may affect the cost of capital. In the final section, I discuss the details of my cost of equity studies and summarize my ROE recommendations.

Q. Please summarize your cost of equity studies and state your ROE recommendation.

A. I recommend an ROE of 10.75 percent, if TEP's proposed capital structure is approved. If TEP's actual test year capital structure is used, then I recommend an ROE of 11.75

percent. My ROE recommendation is based on alternative versions of the constant growth and multistage growth DCF model and the capital asset pricing model ("CAPM"), and it is confirmed by my basic risk premium analysis and my review of economic conditions expected to prevail during the coming year.

TEP's cost of equity cannot be estimated directly from its own market data because TEP is a wholly-owned subsidiary of Unisource Energy Corporation. As such, TEP does not have publicly traded common stock or other independent market data that would be required to estimate its cost of equity directly. I apply the DCF models and the CAPM to a conservative sample of investment grade electric utilities selected from the *Value Line Investment Survey* (Value Line). To be included in my comparable company group, companies were required to have a minimum investment grade (Baa/BBB or higher) bond rating by either Moody's or Standard & Poor's (S&P), to derive at least 65 percent of revenues from regulated utility sales, to have consistent financial records not affected by recent mergers or restructuring, and to have a consistent dividend record as required by the DCF model.

To test my DCF results, I provide a bond yield plus equity risk premium analysis based on Moody's Baa cost of utility debt. This is the appropriate basis for the risk premium analysis since TEP's primary rate of return request is based on an investment grade capital structure and the investment grade comparable company group for estimating ROE.[1]

I also present S&P's forecasts for economic growth and for expected interest rates over the coming year. The S&P forecasts indicate continuing economic growth and higher

[1] TEP's alternative rate of return request is calculated from its actual capital structure and an increment to ROE based on a non-investment grade bond rating.

interest rates. Under current economic, market, and electric utility industry conditions, this combination approach is the most appropriate for estimating the fair cost of equity capital. The data sources and the details of my rate of return analysis are contained in Exhibits SCH-1 through SCH-9.

My DCF analysis indicates that an ROE range of 10.4 percent to 10.8 percent is appropriate. My CAPM analysis indicates a wider range with a midpoint ROE estimate of 11.1 percent. As I will explain in more detail later, the DCF results from the traditional constant growth DCF model fail to meet basic checks of reasonableness and, therefore, those results are not included in the estimated DCF range. The traditional constant growth DCF results do not reasonably reflect the current cost of equity because those results depend on historically low dividend yields and pessimistic analysts' growth forecasts. Under these circumstances, the traditional constant growth DCF model, with growth rates based on traditional analysts' growth rate sources, does not adequately reflect the market's required rate of return. My risk premium analysis, which serves as a check of reasonableness for the DCF and CAPM results, indicates an ROE of 10.83. I will also discuss other risk premium studies that indicate current ROEs as high as 11.4 percent.

Because recent interest rate and stock price data have a significant effect on the ROE estimation models, the analytical results should be evaluated carefully. Particularly for the traditional constant growth DCF model, extreme market volatility for utility shares and low analyst growth rate estimates should be considered. In my DCF analysis, I offer several alternatives for estimating the long-term DCF growth rate and an extensive review of recent changes in analysts' growth rate projections. These data demonstrate that a more general approach, based on projected increases in interest rates and other capital market costs, is currently required for estimating the cost of equity capital.

With consideration for all these factors, based on the results of my DCF and CAPM analyses, I estimate the current cost of equity range to be in the range of 10.4 percent to 11.1 percent. With further consideration for my risk premium analysis and review of projected interest rate for the coming year, my point ROE estimate for the investment grade comparable group is 10.75 percent. In the alternative, I also present an analysis of the spreads between investment grade and non-investment grade bond interest rates. I then use these average differences, or yield spreads, to recommend an increment to the base ROE estimate of 100 basis points. When this increment is added, the non-investment grade company ROE estimate is 11.75 percent. As I will discuss in more detail later, the 10.75 percent ROE is appropriate if TEP's proposed capital structure is adopted; the 11.75 percent is appropriate if the Company's actual test year capital structure is used.

Q. Please explain your non-investment grade alternative ROE estimate.

A. My analysis of the differences, or spreads, between investment grade (BBB or above) utility bond interest rates and non-investment grade (BB and below) utility bond interest rates is presented in Exhibit SCH-1. That analysis shows that recent spreads have averaged between 80 and 120 basis points. Longer-term historical averages indicate much wider spreads, often in the range of 100 to 200 basis points, or more. Based on this analysis, I estimate the cost of equity for non-investment grade utilities to be at least 100 basis points higher than my cost of equity estimate for the investment grade comparable company group. The indicated non-investment grade cost of equity is, therefore, 11.75 percent.

Q. Why did you use yield spreads from BB versus BBB bonds to estimate the non-investment grade increment to ROE?

A. As shown in Exhibit SCH-1, the difference in borrowing costs for BB versus BBB companies can be measured. Such spreads are a basic indication of the incremental return that bond investors require to accept the higher BB risk. Although it can be argued that, when a company's bond rating falls below investment grade, the additional risk for equity investors is higher than for bond investors, that increment is difficult to measure. Therefore, I have conservatively estimated the required increment to ROE from the basic bond yield spread data.

III. STRUCTURAL ORGANIZATION AND OPERATING CHARACTERISTICS OF TEP.

Q. Please describe TEP's structural organization and operating characteristics?

A. TEP is the principal utility operating subsidiary of UniSource Energy Corporation ("UniSource Energy"). TEP's primary service territory is located in the Tucson metropolitan area and includes portions of Pima County and Cochise County, Arizona. For 2006, TEP provided 76 percent of UniSource Energy's operating revenues and comprised 82 percent of its assets. UniSource Energy has two additional utility subsidiaries, UNS Gas and UNS Electric, which were acquired from Citizen's Communications in 2003. UNS Gas and UNS Electric provide service in 30 communities in northern and southern Arizona. UNS Gas and UNS Electric are not part of the present rate request filing.

TEP serves a diverse group of residential, commercial, industrial, and public authority customers. In 2006, TEP's retail revenues were almost $775 million. Based on energy sales volume, residential customers accounted for 41 percent of total sales; commercial

customers, 21 percent; mining and non-mining industrial customers, 35 percent; and public authority customers, 3 percent. In addition, TEP obtained almost $188 million of revenues from wholesale transactions in 2006. TEP's dependence on commercial, industrial, and wholesale revenues is important because sales to such customers may be significantly affected by changes in economic conditions or other factors beyond TEP's control. These and other operating risk characteristics are reflected in the Company's business risk profile from Standard & Poor's of 6 (with 1 being lowest risk and 10 being highest risk) and its below investment grade corporate bond rating of BB.

Q. What is the nature of TEP's power supply?

A. For its power supply, TEP relies on owned and leased generation as well as long-term and short-term purchased power contracts. At December 31, 2006, total owned capacity was 1,658 megawatts (MW) and leased capacity was 536 MW. In addition, TEP had access to 719 MW of additional resources, consisting of certain capacity purchases and interruptible retail load.

Most of the generation capacity owned or leased by TEP is coal fired, including the Springerville Station (760 MW), the San Juan Station (322 MW), the Navajo Station (168 MW), and the Four Corners Station (110 MW). Its newest natural gas-fired generation source is the Luna Energy Facility of which it owns 190 MW.

Q. How have the rating agencies responded to TEP's circumstances?

A. While TEP's credit scores have been stable to improving over the last year, the rating agencies cite significant risks still facing the Company. In September 2006, Moody's upgraded the long-term ratings of TEP by one notch, including its senior secured debt to Baa2 from Baa3 and its issuer rating to Baa3 from Ba1. Standard & Poor's revised its

outlook for the Company from negative to stable in March 2006. The Company currently has a corporate rating of BB from S&P and a senior secured rating of BBB-.

The rating agencies state that TEP's ratings are driven by its relatively stable, regulated cash flow, its growing service territory, its low cost predominantly coal-fired generation base, and a debt reduction strategy that has resulted in improved cash flow metrics. However, they also refer to significant uncertainties facing the Company. Moody's notes that its ratings "reflect the company's high book leverage and significant regulatory uncertainty" (Moody's Investors Service, Global Credit Research Credit Opinion, September 19, 2006). S&P states that factors driving TEP's slightly higher than average business risk position include "a rate cap that is in place through 2008 that leaves TEP vulnerable to unplanned outages and uncertainties over how TEP's rates will be determined after the rate freeze ends." (Standard & Poor's Ratings Direct, December 18, 2006).

Q. How does TEP's requested capital structure compare to the capital structures of the companies in your investment grade comparable company group?

A. TEP's requested capital structure containing 55 percent debt and 45 percent equity is similar to, though somewhat more highly leveraged than, the year-end 2006 average capital structure for my investment grade comparable company group. The capital structure parameters for each of those companies at year-end 2006 and as projected for the 2010-2012 time period by Value Line are shown in Exhibit SCH-2. These data strongly support TEP's requested 55/45 debt-to-equity capital structure and demonstrate the improving financial metrics that are expected for the electric utility industry.

Q. How does TEP's level of required capital spending compare to the capital spending of your comparable companies.

A. TEP's capital requirements are about 20 percent larger, relative to existing net plant, than the average for my comparable company group. The data that support this comparison are presented in Exhibit SCH-3. In that exhibit, I compare TEP's projected capital spending for the next 6 years to the Company's existing net plant at year-end 2006. That comparison shows that TEP expects to increase its net plant by about 80 percent over the next 6 years. The same statistic for the investment grade comparable companies that I used to estimate ROE shows that, on average, those companies will increase net plant by about 65 percent over the next 6 years. While I have not added a construction risk increment to TEP's requested rate of return, these comparisons illustrate the relatively large financing requirements that TEP faces and show the importance of improved financial condition for the Company. Its capital market access and the costs the Company will pay for the required capital depend significantly on less financial leverage and improvement in other financial metrics.

IV. ESTIMATING THE COST OF EQUITY CAPITAL.

Q. What is the purpose of this section of your testimony?

A. The purpose of this section is to present a general definition of the cost of equity and to compare the strengths and weaknesses of several of the most widely used methods for estimating the cost of equity. Estimating the cost of equity is fundamentally a matter of informed judgment. The various models provide a concrete link to actual capital market data and assist with defining the various relationships that underlie the ROE estimation process.

Q. Please define the term "cost of equity capital" and provide an overview of the cost estimation process.

A. The cost of equity capital is the profit or rate of return that equity investors expect to receive. In concept it is no different than the cost of debt or the cost of preferred stock. The cost of equity is the rate of return that common stockholders expect, just as interest on bonds and dividends on preferred stock are the returns that investors in those securities expect. Equity investors expect a return on their capital commensurate with the risks they take and consistent with returns that might be available from other similar investments. Unlike returns from debt and preferred stocks, however, the equity return is not directly observable in advance and, therefore, it must be estimated or inferred from capital market data and trading activity.

An example helps to illustrate the cost of equity concept. Assume that an investor buys a share of common stock for $20 per share. If the stock's expected dividend is $1.00, the expected dividend yield is 5.0 percent ($1.00 / $20 = 5.0 percent). If the stock price is also expected to increase to $21.20 after one year, this one dollar and 20 cent expected gain adds an additional 6.0 percent to the expected total rate of return ($1.20 / $20 = 6.0 percent). Therefore, buying the stock at $20 per share, the investor expects a total return of 11.0 percent: 5.0 percent dividend yield, plus 6.0 percent price appreciation. In this example, the total expected rate of return at 11.0 percent is the appropriate measure of the cost of equity capital, because it is this rate of return that caused the investor to commit the $20 of equity capital in the first place. If the stock were riskier, or if expected returns from other investments were higher, investors would have required a higher rate of return from the stock, which would have resulted in a lower initial purchase price in market trading.

Each day market rates of return and prices change to reflect new investor expectations and requirements. For example, when interest rates on bonds and savings accounts rise, utility stock prices usually fall. This is true, at least in part, because higher interest rates on these alternative investments make utility stocks relatively less attractive, which causes utility stock prices to decline in market trading. This competitive market adjustment process is quick and continuous, so that market prices generally reflect investor expectations and the relative attractiveness of one investment versus another. In this context, to estimate the cost of equity one must apply informed judgment about the relative risk of the company in question and knowledge about the risk and expected rate of return characteristics of other available investments as well.

Q. How does the market account for risk differences among the various investments?

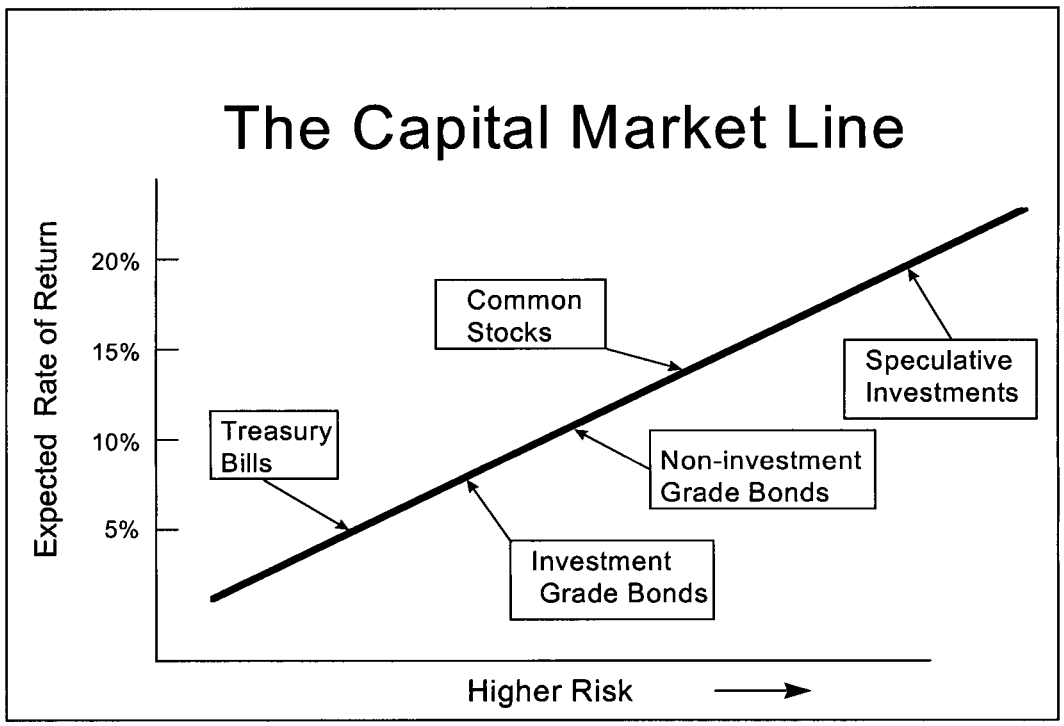
A. Risk-return tradeoffs among capital market investments have been the subject of extensive financial research. Literally dozens of textbooks and hundreds of academic articles have addressed the issue. Generally, such research confirms the common sense conclusion that investors will take additional risks only if they expect to receive a higher rate of return. Empirical tests consistently show that returns from low-risk securities, such as U.S. Treasury bills, are the lowest; that returns from longer-term Treasury bonds and corporate bonds are increasingly higher as risks increase; and generally, returns from common stocks and other more risky investments are even higher. These observations provide a sound theoretical foundation for both the DCF and risk premium methods for estimating the cost of equity capital. These methods attempt to capture the well-founded risk-return principle and explicitly measure investors' rate of return requirements.

Q. Can you illustrate the capital market risk-return principle that you just described?

A. Yes. The following graph depicts the risk-return relationship that has become widely known as the Capital Market Line ("CML"). The CML offers a graphical representation

of the capital market risk-return principle. The graph is not meant to illustrate the actual expected rate of return for any particular investment, but merely to illustrate in a general way the risk-return relationship.

Risk-Return Tradeoffs



As a continuum, the CML can be viewed as an available opportunity set for investors. Those investors with low risk tolerance or investment objectives that mandate a low risk profile should invest in assets depicted in the lower left-hand portion of the graph. Investments in this area, such as Treasury bills and short-maturity, high quality corporate commercial paper, offer a high degree of investor certainty. In nominal terms (before considering the potential effects of inflation), such assets are virtually risk-free.

Investment risks increase as one moves up and to the right along the CML. A higher degree of uncertainty exists about the level of investment value at any point in time and

about the level of income payments that may be received. Among these investments, long-term bonds and preferred stocks, which offer priority claims to assets and income payments, are relatively low risk, but they are not risk-free. The market value of long-term bonds, even those issued by the U.S. Treasury, often fluctuates widely when government policies or other factors cause interest rates to change.

Farther up the CML continuum, common stocks are exposed to even more risk, depending on the nature of the underlying business and the financial strength of the issuing corporation. Common stock risks include market-wide factors, such as general changes in capital costs, as well as industry and company specific elements that may add further to the volatility of a given company's performance. As I will illustrate in my risk premium analysis, common stocks typically are more volatile (have higher risk) than high quality bond investments and, therefore, they reside above and to the right of bonds on the CML graph. Other more speculative investments, such as stock options and commodity futures contracts, offer even higher risks (and higher potential returns). The CML's depiction of the risk-return tradeoffs available in the capital markets provides a useful perspective for estimating investors' required rates of return.

Q. How is the fair rate of return in the regulatory process related to the estimated cost of equity capital?

A. The regulatory process is guided by fair rate of return principles established in the U.S. Supreme Court cases, *Bluefield Water Works* and *Hope Natural Gas*:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-693 (1923).

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

Based on these principles, the fair rate of return should closely parallel investor opportunity costs as discussed above. If a utility earns its market cost of equity, neither its stockholders nor its customers should be disadvantaged.

Q. What specific methods and capital market data are used to evaluate the cost of equity?

A. Techniques for estimating the cost of equity normally fall into three groups: comparable earnings methods, risk premium methods, and DCF methods. The first set of estimation techniques, the comparable earnings methods, has evolved over time. The original comparable earnings methods were based on book accounting returns. This approach developed ROE estimates by reviewing accounting returns for unregulated companies thought to have risks similar to those of the regulated company in question. These methods have generally been rejected because they assume that the unregulated group is earning its actual cost of capital, and that its equity book value is the same as its market value. In most situations these assumptions are not valid, and, therefore, accounting-based methods do not generally provide reliable cost of equity estimates.

More recent comparable earnings methods are based on historical stock market returns rather than book accounting returns. While this approach has some merit, it too has been criticized because there can be no assurance that historical returns actually reflect current or future market requirements. Also, in practical application, earned market returns tend

to fluctuate widely from year to year. For these reasons, a current cost of equity estimate (based on the DCF model or a risk premium analysis) is usually required.

The second set of estimation techniques is grouped under the heading of risk premium methods. These methods begin with currently observable market returns, such as yields on government or corporate bonds, and add an increment to account for the additional equity risk. The capital asset pricing model ("CAPM") and arbitrage pricing theory ("APT") model are more sophisticated risk premium approaches. The CAPM and APT methods estimate the cost of equity directly by combining the "risk-free" government bond rate with explicit risk measures to determine the risk premium required by the market. Although these methods are widely used in academic cost of capital research, their additional data requirements and the wider range of ROE estimates they sometimes produce have detracted from their use in some regulatory jurisdictions. The basic bond yield plus equity risk premium method also provides a useful parallel approach and assures consistency with other capital market data in the cost of equity cost estimation process.

The third set of estimation techniques, based on the DCF model, is the most widely used regulatory cost of equity estimation method. Like the risk premium approach, the DCF model has a sound basis in theory, and many argue that it has the additional advantage of simplicity. I will describe the DCF model in detail below, but in essence its estimate of ROE is simply the sum of the expected dividend yield and the expected long-term dividend (or price) growth rate. While dividend yields are easy to obtain, estimating long-term growth is more difficult. Because the constant growth DCF model also requires very long-term growth estimates (technically to infinity), some argue that its application is too speculative to provide reliable results, resulting in the preference for the multistage growth DCF analysis.

Q. Of the three estimation methods, which do you believe provides the most reliable results?

A. From my experience, a combination of discounted cash flow and risk premium methods provides the most reliable approach. While the caveat about estimating long-term growth must be observed, the DCF model's other inputs are readily obtainable, and the model's results typically are consistent with capital market behavior. The risk premium methods provide a good parallel approach to the DCF model and further ensure that current market conditions are accurately reflected in the cost of equity estimate. Although I have typically placed more weight on the DCF results, under present market conditions additional methods should be considered. Given this Commission's prior reliance on both the DCF model and the CAPM, I have included the results from my CAPM analysis along with my DCF results in my recommended ROE range.[2]

Q. Please explain the DCF model.

A. The DCF model is predicated on the concept that stock prices represent the present value or discounted value of all future dividends that investors expect to receive. In the most general form, the DCF model is expressed in the following formula:

$$P_0 = D_1/(1+k) + D_2/(1+k)^2 + \ldots + D_\infty/(1+k)^\infty \qquad (1)$$

In this formula, P_0 is today's stock price; D_1, D_2, etc. are all future dividends and k is the discount rate, or the investor's required rate of return on equity. Equation (1) is a routine present value calculation based on the assumption that the stock's price is the present value of all dividends expected to be paid in the future.

[2] See, for example, ACC Docket No. WS-01303A-06-0014, Decision No. 69440 (May 1, 2007) at 19-20.

Under the additional assumption that dividends are expected to grow at a constant rate "g" and that k is strictly greater than g, equation (1) can be solved for k and rearranged into the simple form:

$$k = D_1/P_0 + g \qquad (2)$$

Equation (2) is the familiar constant growth DCF model for cost of equity estimation, where D_1/P_0 is the expected dividend yield and g is the long-term expected dividend growth rate.

Under circumstances when growth rates are expected to fluctuate or when future growth rates are highly uncertain, the constant growth model may not give reliable results. Although the DCF model itself is still valid [equation (1) is mathematically correct], under such circumstances the simplified form of the model must be modified to capture market expectations accurately.

Recent events and current market conditions in the electric utility industry as discussed later appear to challenge the constant growth assumption of the traditional DCF model. Since the mid-1980s, dividend growth expectations for many electric utilities have fluctuated widely. In fact, over one-third of the electric utilities in the U.S. have reduced or eliminated their common dividends over this time period. Some of these companies have reestablished their dividends, producing exceptionally high growth rates. Under these circumstances, long-term growth rate estimates may be highly uncertain, and estimating a reliable "constant" growth rate for many companies is often difficult.

Q. Can the DCF model be applied when the constant growth assumption is violated?

A. Yes. When growth expectations are uncertain, the more general version of the model represented in equation (1) should be solved explicitly over a finite "transition" period while uncertainty prevails. The constant growth version of the model can then be applied after the transition period, under the assumption that more stable conditions will prevail in the future. There are two alternatives for dealing with the non-constant growth transition period.

Under the "terminal price" non-constant growth approach, equation (1) is written in a slightly different form:

$$P_0 = D_1/(1+k) + D_2/(1+k)^2 + \ldots + P_T/(1+k)^T \qquad (3)$$

Here, the variables are the same as in equation (1) except that P_T is the estimated stock price at the end of the transition period T. Under the assumption that normal growth resumes after the transition period, the price P_T is then expected to be based on constant growth assumptions. With the terminal price approach, the estimated cost of equity, k, is just the rate of return that investors would expect to earn if they bought the stock at today's market price, held it and received dividends through the transition period (until period T), and then sold it for price P_T. In this approach, the analyst's task is to estimate the rate of return that investors expect to receive given the current level of market prices they are willing to pay.

Under the "multistage" non-constant growth approach, equation (1) is simply expanded to incorporate two or more growth rate periods, with the assumption that a permanent constant growth rate can be estimated for some point in the future:

$$P_0 = D_0(1+g_1)/(1+k) + \ldots + D_0(1+g_2)^n/(1+k)^n + \ldots + D_0(1+g_T)^{(T+1)}/(k-g_T) \quad (4)$$

Here, the variables are the same as in equation (1), but g_1 represents the growth rate for the first period, g_2 for a second period, and g_T for the period from year T (the end of the transition period) to infinity. The first two growth rates are simply estimates for fluctuating growth over "n" years (typically 5 or 10 years) and g_T is a constant growth rate assumed to prevail forever after year T. The difficult task for analysts in the multistage approach is determining the various growth rates for each period.

Although less convenient for exposition purposes, the non-constant growth models are based on the same valid capital market assumptions as the constant growth version. The non-constant growth approach simply requires more explicit data inputs and more work to solve for the discount rate, k. Fortunately, the required data are available from investment and economic forecasting services, and computer algorithms can easily produce the required solutions. Both constant and non-constant growth DCF analyses are presented in the following section.

Q. Please explain the risk premium methodology.

A. Risk premium methods are based on the assumption that equity securities are riskier than debt and, therefore, that equity investors require a higher rate of return. This basic premise is well supported by legal and economic distinctions between debt and equity securities, and it is widely accepted as a fundamental capital market principle. For example, debt holders' claims to the earnings and assets of the borrower have priority over all claims of equity investors. The contractual interest on mortgage debt must be paid in full before any dividends can be paid to shareholders, and secured mortgage claims must be fully satisfied before any assets can be distributed to shareholders in

bankruptcy. Also, the guaranteed, fixed-income nature of interest payments makes year-to-year returns from bonds typically more stable than capital gains and dividend payments on stocks. All these factors demonstrate the more risky position of stockholders and support the equity risk premium concept.

Q. Are risk premium estimates of the cost of equity consistent with other current capital market costs?

A. Yes. The risk premium approach is especially useful because it is founded on current market interest rates, which are directly observable. This feature assures that risk premium estimates of the cost of equity begin with a sound basis, which is tied directly to current capital market costs.

Q. Is there similar consensus about how risk premium data should be employed?

A. No. In regulatory practice, there is often considerable debate about how risk premium data should be interpreted and used. Since the analyst's basic task is to gauge investors' required returns on long-term investments, some argue that the estimated equity spread should be based on the longest possible time period. Others argue that market relationships between debt and equity from several decades ago are irrelevant and that only recent debt-equity observations should be given any weight in estimating investor requirements. There is no consensus on this issue. Since analysts cannot observe or measure investors' expectations directly, it is not possible to know exactly how such expectations are formed or, therefore, to know exactly what time period is most appropriate in a risk premium analysis.

The important point is to answer the following question: "What rate of return should equity investors reasonably expect relative to returns that are currently available from long-term bonds?" The risk premium studies and analyses I discuss later address this

question. My risk premium recommendation is based on an intermediate position that avoids some of the problems and concerns that have been expressed about both very long and very short periods of analysis with the risk premium model.

Q. Please summarize your discussion of cost of equity estimation techniques.

A. Estimating the cost of equity is one of the most controversial issues in utility ratemaking. Because actual investor requirements are not directly observable, several methods have been developed to assist in the estimation process. The comparable earnings method is the oldest but perhaps least reliable. Its use of accounting rates of return, or even historical market returns, may or may not reflect current investor requirements. Differences in accounting methods among companies and issues of comparability also detract from this approach.

The DCF and risk premium methods have become the most widely accepted in regulatory practice. A combination of the DCF model and a review of risk premium data provides the most reliable cost of equity estimate. While the DCF model does require judgment about future growth rates, the dividend yield is straightforward, and the model's results are generally consistent with actual capital market behavior. For these reasons, I will rely on a combination of the DCF model and a risk premium analysis in the cost of equity studies that follow.

V. FUNDAMENTAL FACTORS THAT AFFECT THE COST OF EQUITY.

Q. What is the purpose of this section of your testimony?

A. In this section, I review recent capital market conditions and industry and company-specific factors that should be reflected in the cost of capital estimate.

Q. What has been the recent experience in the U.S. capital markets?

A. Exhibit SCH-4, page 1, provides a review of annual interest rates and rates of inflation in the U.S. economy over the past ten years. During that time, inflation and capital market costs have declined and, generally, have been lower than rates that prevailed in the previous decade. Inflation, as measured by the Consumer Price Index, until 2005 had remained at historically low levels not seen consistently since the early 1960s. Inflation rates for 2005 and 2006 were similar to longer-term historical averages in excess of 3 percent. With improving economic conditions, since mid-2004, the Federal Reserve System has increased the short-term Federal Funds interest rate 17 times, raising it from 1 percent to a present level of 5.25 percent. Although long-term interest rates have been slower to increase up, they are currently about 40 basis points above their lowest levels reached in mid-2005. Estimates for the next 12 months are for continued economic growth and for higher interest rates.

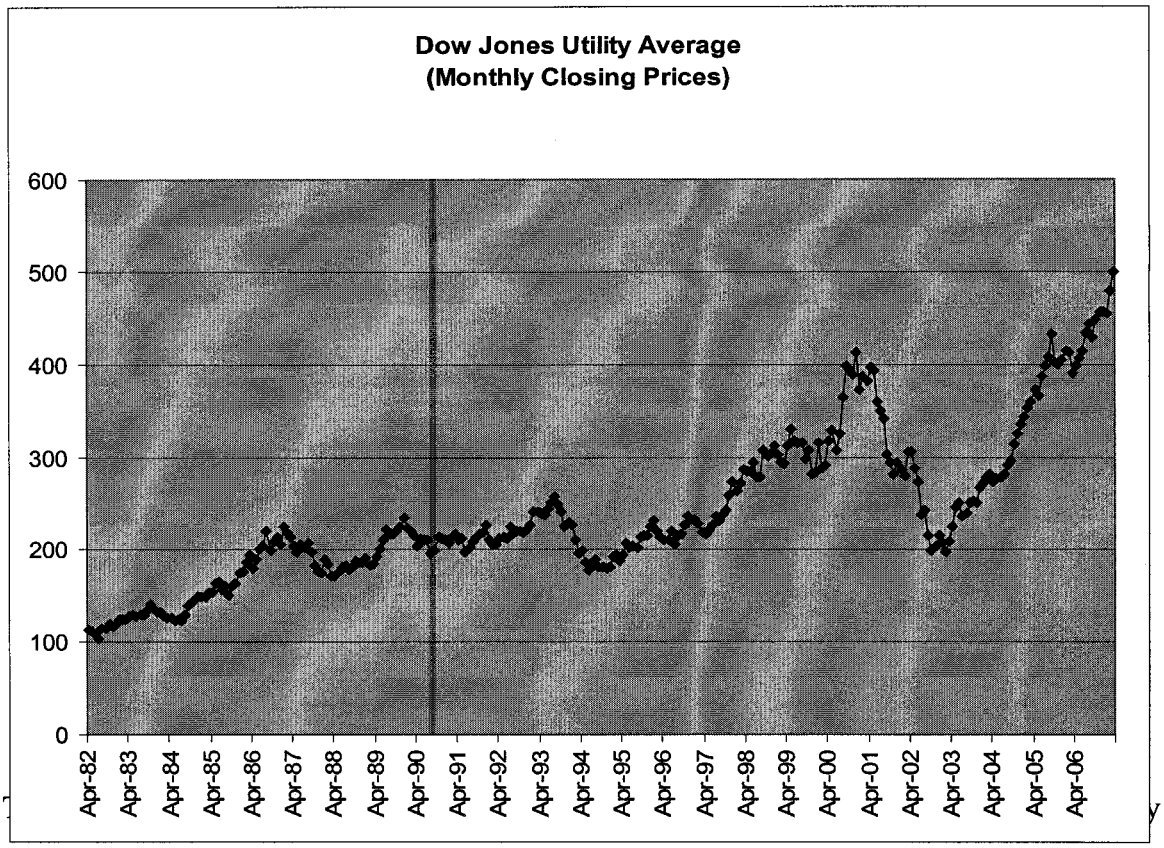
Exhibit SCH-4, page 2, provides a summary of Moody's Average Utility and Baa Utility Bond Yields for the past two years. The Average Utility and Baa Utility rates at March 2007 were 5.87 percent and 6.10 percent, respectively. These levels represent increases of 40 to 50 basis points from mid-2005 levels.

Exhibit SCH-4, page 3, provides Standard and Poor's *Trends & Projections* forecasts for April 19, 2007. The forecast data show expectations for continuing, albeit slower, economic growth. Growth in *real* Gross Domestic Product (GDP) for 2007 is projected at 2.4 percent and *nominal* GDP (real GDP plus inflation) is projected at 5.0 percent. These projected GDP growth rates compare to a nominal rate for 2006 at a level of 6.4 percent and a real growth rate of 3.3 percent. S&P also forecasts that interest rates will rise from current levels. The 10-year Treasury Note is projected to increase from its current level of about 4.7 percent to 4.9 percent by the 2nd quarter of 2008 and to average

5.0 percent for the coming year. Long-term Treasury Bonds are projected to increase from current levels of about 4.8 percent to an average of 5.2 percent for 2008, and Corporate Bonds are projected to increase from current levels of about 5.5 percent to 5.8 percent for 2008. These increasing interest rate trends offer important perspective for judging the cost of capital in the present case.

Q. How have utility stocks performed during the past several years?

A. Utility stock prices have fluctuated widely. After reaching a level of 310 in April 2002, the Dow Jones Utility Average (DJUA) dropped to below 180 by October 2002. Since late 2002, the Average has trended upward. Its current level at over 500 is near a record high level. The wider fluctuations in more recent years are vividly illustrated in the following graph of DJUA prices over the past 25 years.



services, will likely create further uncertainties and market volatility for utility shares. In this environment, investors' return expectations and requirements for providing capital to

the utility industry remain high relative to the longer-term traditional view of the utility industry.

Q. What is the industry's current fundamental position?

A. Many electric utilities are attempting to return to their core businesses and hope to see more stable results over the next several years. S&P reflects this sentiment in its most recent *Electric Utility Industry Survey*:

> **Standard & Poor's Industry Surveys**
>
> Although we expect the performance of both the electric utility sector and the individual companies within the sector to remain volatile over the next several years, we expect the stocks to become less volatile than they have been in the past few years. (Standard & Poor's Industry Surveys, Electric Utilities, February 15, 2007, p. 5)

In a recent edition covering electric utilities, *Value Line* also reflected concerns about interest rates and utility operating risks:

> **Value Line Investors' Service**
>
> Economists have assigned a low probability to the likelihood of an easing of the Federal Reserve's monetary policy in early 2007. (Rate cuts usually lend a boost to utility stocks.) We expect 2007 to be a fairly good year for the eastern electrics.... Still, the utilities' capital budgets have increased because of the need for more capacity and improved service reliability. Recovery of these outlays (and high fuel costs) via electricity tariffs poses some risk. (*Value Line*, December 1, 2006, p. 157)

Extreme price volatility for utility shares and expectations for rising interest rates make it more difficult to estimate the fair, on-going cost of capital. Analysts' near-term growth estimates for utilities reflect the issues described by Value Line and current three-to-five-year projections are low. As I will discuss in more detail later, this feature raises significant questions about using analysts' current growth projections as proxies for long-term growth in the DCF model.

Over the past several years, the greatest consideration for utility investors has been the industry's transition to competition. With the passage of the National Energy Policy Act ("NEPA") in 1992 and the Federal Energy Regulatory Commission's ("FERC") Order 888 in 1996, the stage was set for vastly increased competition in the electric utility industry. NEPA's mandate for open access to the transmission grid and FERC's implementation through Order 888 effectively opened the market for wholesale electricity to competition. Previously protected utility service territory and lack of transmission access in some parts of the country had limited the availability of competitive bulk power prices. NEPA and Order 888 have essentially eliminated such constraints for incremental power needs.

In addition to wholesale issues at the federal level, many states implemented retail access and have opened their retail markets to competition. As expected, the opening of previously protected utility markets to competition, and the uncertainty created by the removal of regulator protection, has raised the level of uncertainty about investment returns across the entire industry.

Q. Is TEP affected by these same market uncertainties and increasing utility capital costs?

A. Yes. To some extent all electric utilities are being affected by the industry's transition to competition. Although the Commission's rules implementing retail electric competition have been challenged in court and questions remain about implementation, TEP's power costs and other operating activities have been significantly affected by transition and restructuring events around the country. In fact, the uncertainty associated with the changes that are transforming the utility industry as a whole, as viewed from the perspective of the investor, remain a factor in assessing any utility's required ROE, including the ROE from TEP's operations in Arizona.

Q. How do capital market concerns and financial risk perceptions affect the cost of equity capital?

A. As I discussed previously, equity investors respond to changing assessments of risk and financial prospects by changing the price they are willing to pay for a given security. When the risk perceptions increase or financial prospects decline, investors refuse to pay the previously existing market price for a company's securities and market supply and demand forces then establish a new lower price. The lower market price typically translates into a higher cost of capital through a higher dividend yield requirement as well as the potential for increased capital gains if prospects improve. In addition to market losses for prior shareholders, the higher cost of capital is transmitted directly to the company by the need to issue more shares to raise any given amount of capital for future investment. The additional shares also impose additional future dividend requirements and reduce future earnings per share growth prospects.

Q. How have regulatory commissions responded to these changing market and industry conditions?

A. On balance, allowed rates of return have changed less than interest rates over the past five years. The following table summarizes electric utility ROEs allowed by state regulatory commissions since 2003:

Authorized Electric Utility Equity Returns

	2003	2004	2005	2006	2007
1st Quarter	11.47%	11.00%	10.51%	10.38%	10.30%
2nd Quarter	11.16%	10.54%	10.05%	10.69%	
3rd Quarter	9.95%	10.33%	10.84%	10.06%	
4th Quarter	11.09%	10.91%	10.75%	10.39%	
Full Year	10.97%	10.75%	10.54%	10.36%	10.30%
No. of Cases	22	19	29	25	8
T&D Cases	4	3	6	10	3
Average Utility Debt Cost	6.61%	6.20%	5.67%	6.08%	5.92%
Indicated Risk Premium	4.36%	4.55%	4.87%	4.28%	4.38%

Source: *Regulatory Focus*, Regulatory Research Associates, Inc., Major Rate Case Decisions, April 3, 2007.[3]

During 2005, interest rates declined to their lowest levels since the 1960s. Allowed equity returns followed the interest rate decline but declined by a smaller amount. Similarly, as interest rates increased during the first half of 2006, allowed ROEs changed little from the prior year's average. Since 2003, equity risk premiums (the difference between allowed equity returns and utility interest rates) have ranged from 4.28 percent to 4.87 percent. At the low end of this risk premium range, with an allowed equity risk premium of about 4.3 percent, the indicated cost of equity is 10.8 percent (6.5% projected Baa interest rate + 4.3% risk premium = 10.8%). At the upper end of this risk premium range, with an allowed equity risk premium of about 4.9 percent, the indicated cost of equity is 11.4 percent (6.5% projected Baa interest rate + 4.9% risk premium = 11.4%). The basis for the 6.5% projected Baa interest rate is provided on Exhibit SCH-9.

[3] The RRA averages, particularly for 2006 and 2007, are lower due to an increasing percentage of Transmission and Distribution (T&D) only companies. The average ROEs for T&D companies for 2006 and 2007 were 9.91 percent and 10.06 percent, respectively. For integrated electric companies like TEP, the average ROEs for 2006 and 2007 were 10.65 percent and 10.44 percent, respectively.

VI. COST OF EQUITY CAPITAL FOR TEP.

Q. What is the purpose of this section of your testimony?

A. The purpose of this section is to present my quantitative studies of the cost of equity capital for TEP and to discuss the details and results of my analysis.

Q. How are your studies organized?

A. In the first part of my analysis, I apply the DCF model and the CAPM to a 28-company group of electric utilities based on the selection criteria discussed previously in Section II of my testimony. In the second part of my analysis, I apply various risk premium models and review projected economic conditions and projected capital costs for the coming year.

My DCF analysis is based on three versions of the DCF model. In the first version of the DCF model, I use the constant growth format with long-term expected growth estimated from an equally weighted, four-part average of (1) Value Line and (2) Zacks earnings per share growth projections for the coming three to five years, (3) a sustainable growth ("b" times "r") estimate based on Value Line's projected retention rates and earned rates of return for the next three to five years, and (4) a long-term estimate of nominal growth in GDP. In the second version of the DCF model, for the estimated growth rate, I use only the long-term estimated GDP growth rate. In the third version of the DCF model, I use a two-stage growth approach, with stage one based on Value Line's three-to-five-year dividend projections and stage two based on long-term projected growth in GDP. The dividend yields in all three of the annual models are from Value Line's projections of dividends for the coming year and stock prices are from the three-month average for the months that correspond to the Value Line editions from which the underlying financial data are taken.

In my CAPM analysis, I apply "long-term" and "short-term" versions of the model. I used both approaches because there is no consensus about which one is best. The short-term CAPM is technically the correct version of the model, because the short-term Treasury bill rate is the best proxy for the risk-free rate. From a practical perspective, however, the long-term version is often preferred. In the long-term CAPM, the Treasury bond rate is used for the risk-free rate, which some believe is a better match for estimating the cost of equity. Because there is no consensus on these issues, I present the results from both versions as a range.

For both versions of the CAPM, for the estimated beta coefficient I use the average of the 28-company comparable group beta coefficients from Value Line. I calculate the estimated market risk premium in both the long-term and short-term models as the average of Ibbotson's geometric and arithmetic mean risk premiums for the 1926-2006 period.[4] In the long-term version of the model, I use the current 30-year U.S. Treasury bond interest rate as the risk-free rate, and in the short-term version of the model I use the 90-day U.S. Treasury bill rate as the risk-free rate. Under present interest rate conditions, the results from the long-term and short-term versions of the CAPM provide a relatively wide range, which I believe reasonably brackets the current cost of equity capital.

Q. Why do you use long-term GDP growth to estimate long-term growth expectations in the DCF model?

A. In recent years, analysts' growth rate projections, which have traditionally be used in DCF studies, have fluctuated widely and have declined significantly from levels that existed five years ago. These fluctuations raise serious questions about the use of such growth rate estimates in the traditional *constant growth* version of the DCF model.

[4] Morningstar (formerly Ibbotson Associates), Stocks, Bonds, Bills, and Inflation 2007 Yearbook, page 31.

Under these circumstances, a broader, more stable indicator of expected growth is required.

Growth in nominal GDP (real GDP plus inflation) is the most general measure of economic growth in the U.S. economy. For long time periods, such as those used in the Ibbotson Associates rate of return data, GDP growth has averaged between 5 percent and 8 percent per year. From this observation, Professors Brigham and Houston offer the following observation concerning the appropriate long-term growth rate in the DCF Model:

> Expected growth rates vary somewhat among companies, but dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation). On this basis, one might expect the dividend of an average, or "normal," company to grow at a rate of 5 to 8 percent a year. (Eugene F. Brigham and Joel F. Houston, *Fundamentals of Financial Management*, 11th Ed. 2007, page 298.)

Other academic research on corporate growth rates offers similar conclusions about GDP growth as well as concerns about the long-term adequacy of analysts' forecasts:

> Our estimated median growth rate is reasonable when compared to the overall economy's growth rate. On average over the sample period, the median growth rate over 10 years for income before extraordinary items is about 10 percent for all firms. ... After deducting the dividend yield (the median yield is 2.5 percent per year), as well as inflation (which averages 4 percent per year over the sample period), the growth in real income before extraordinary items is roughly 3.5 percent per year. This is consistent with the historical growth rate in real gross domestic product, which has averaged about 3.4 percent per year over the period 1950-1998. (Louis K. C. Chan, Jason Karceski, and Josef Lakonishok, "The Level and Persistence of Growth Rates," The Journal of Finance, April 2003, p. 649)

> IBES long-term growth estimates are associated with realized growth in the immediate short-term future. Over long horizons, however, there is little forecastability in earnings, and analysts' estimates tend to be overly optimistic. ... On the whole, the

> absence of predictability in growth fits in with the economic intuition that competitive pressures ultimately work to correct excessively high or excessively low profitability growth. (Ibid, page 683)

These findings support the notion that long-term growth expectations are more closely predicted by broader measures of economic growth than by near-term analysts' estimates. Especially for the very long-term growth rate requirements of the DCF model, the growth in nominal GDP should be considered an important input. For Arizona specifically, the economy is expected to grow more rapidly than the national average due to above-average employment and population growth.

Q. How have analysts' three-to-five year growth projections changed over the past five years?

A. Analysts' forecasted growth rates for electric utilities have fluctuated widely and are lower than five years ago. While the analysts' growth rates have increased somewhat during the past year, they are still significantly lower than they were in 2002. In Exhibit SCH-5, I compare current forecasts from Value Line for my comparable group companies to those that existed in 2002. During 2002, Value Line's projected three-to-five year earnings growth rate was 5.83 percent per year. In the most recent Value Line editions, the average projected earnings growth rate is 5.44 percent. The "b times r" sustainable growth rate based on Value Line's projected retention rates and earned ROEs shows an even larger decline. During 2002, for the comparable electric group the average "b times r" growth rate was 5.30 percent per year. Currently, the "b times r" growth rate from the three most recent Value Line editions is only 3.90 percent. These comparisons further illustrate that analysts' growth rate projections are more volatile than one would expect for perpetual growth rate expectations, and that current projections are very low as compared to those used just five years ago. These results strongly support using more general long-term economic growth rates, such as GDP, in the DCF model.

Q. How did you estimate the expected long-run GDP growth rate?

A. I developed my long-term GDP growth forecast from nominal GDP data contained in the St. Louis Federal Reserve Bank data base. That data for the period 1947 through 2006 is summarized in my Exhibit SCH-6. As shown at the bottom of that exhibit, the overall average for the period was 7.0 percent. The data also show, however, that in the more recent years since 1980, lower inflation has resulted in lower overall GDP growth. For this reason I gave more weight to the more recent years in my GDP forecast. This approach is consistent with the concept that more recent data should have a greater effect on expectations and with generally lower near- and intermediate-term growth rate forecasts that presently exist. Based on this approach, my overall forecast for long-term GDP growth is 40 basis points lower than the long-term average, at a level of 6.6 percent.

Q. Please summarize the results of your electric utility DCF analyses.

A. The DCF results for my comparable company group are presented in Exhibit SCH-7. As shown in the first column of page 1 of that exhibit, the traditional constant growth model indicates an ROE of only 9.3 percent to 9.5 percent. Because this result falls more than 100 basis points below my risk premium checks of reasonableness, it is excluded from my final DCF range. In the second column of page 1, I recalculate the constant growth results with the growth rate based on long-term forecasted growth in GDP. With the higher GDP growth rate, the constant growth model indicates an ROE of 10.8 percent. Finally, in the third column of page 1, I present the results from the multistage DCF model. The multistage model indicates an ROE range of 10.4 percent to 10.5 percent. The results from the DCF model, therefore, indicate a reasonable ROE range of 10.4 percent to 10.8 percent for the comparable company group.

Q. What are the results of your CAPM analysis?

A. The results of my CAPM analysis are shown in Exhibit SCH-8. The long-term CAPM estimate of ROE based on 30-year Treasury bonds is 10.31 percent. The short-term CAPM estimate of ROE based on 90-day Treasury bills as the risk-free rate is 11.81 percent. The midpoint of my two CAPM estimates is 11.06 percent.

Q. What are the results of your risk premium studies?

A. The details and results of my risk premium studies are shown in my Exhibit SCH-9. These studies and other risk premium data indicate an ROE range of 10.8 percent to 11.6 percent.

Q. How are your risk premium studies structured?

A. My risk premium studies are divided into two parts. First, I compare electric utility authorized ROEs for the period 1980-2006 to contemporaneous long-term utility interest rates. The differences between the average authorized ROEs and the average interest rate for the year is the indicated equity risk premium. I then add the indicated equity risk premium to the forecasted Baa utility bond interest rate to estimate ROE. Because there is a strong inverse relationship between risk premiums and interest rates (when interest rates are high, risk premiums are low and vice versa), further analysis is required to estimate the current risk premium level.

The inverse relationship between risk premiums and interest rate levels is well documented in numerous, well-respected academic studies. These studies typically use regression analysis or other statistical methods to predict or measure the risk premium relationship under varying interest rate conditions. On page 2 of Exhibit SCH-9, I provide regression analyses of the allowed annual equity risk premiums relative to interest rate levels. The negative and statistically significant regression coefficients

confirm the inverse relationship between risk premiums and interest rates. This means that when interest rates rise by one percentage point, the cost of equity increases, but by a smaller amount. Similarly, when interest rates decline by one percentage point, the cost of equity declines by less than one percentage point. I use this negative interest rate change coefficient in conjunction with current interest rates to establish the appropriate current equity risk premium.

Q. How do the results of your risk premium study compare to levels found in other published risk premium studies?

A. Based on my risk premium studies, I am conservatively recommending a lower risk premium than is often found in other published risk premium studies. For example, the most widely followed risk premium data are provided in studies published annually by Morningstar, Inc. These data, for the period 1926-2006, indicate an arithmetic mean risk premium of 6.1 percent for common stocks versus long-term corporate bonds. Under the assumption of geometric mean compounding, the Morningstar risk premium for common stocks versus corporate bonds is 4.5 percent. Based on the more conservative geometric mean risk premium, these data indicate a cost of equity of 11.0 percent (6.5% forecasted debt cost + 4.5% risk premium = 11.0%). Based on the arithmetic risk premium, the Morningstar data indicate a cost of equity of 12.6 percent (6.5% forecasted debt cost + 6.1% risk premium = 12.6%).

Harris and Marston (H&M) also provide specific equity risk premium estimates.[5] Using analysts' growth estimates to estimate equity returns, H&M found equity risk premiums of 6.47 percent relative to U.S. Government bonds and 5.13 percent relative to yields on corporate debt. H&M's equity risk premium relative to corporate debt also indicates a current cost of equity of 11.6 percent (6.5% debt cost + 5.13% risk premium = 11.63%).

[5] Robert S. Harris and Felicia C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management*, Summer 1992.

Although the Ibbotson and Harris and Marston results should not be extrapolated directly as stand-alone estimates of the cost of equity for regulated utilities, their results provide a reasonable long-term perspective on capital market expectations for debt and equity rates of return.

Q. Please summarize the results of your cost of equity analysis.

A. The following table summarizes my results:

Summary of Cost of Equity Estimates

DCF Analysis	Indicated Cost
Constant Growth (GDP Growth)	10.8%%
Multistage Growth Model	10.4%-10.5%
Reasonable DCF Range	10.4%-10.8%
CAPM Analysis	**Indicated Cost**
Long-term (5.07% + 0.91 x 5.75%)	10.31%
Short-term (4.89% + 0.91 x 7.60%)	11.81%
CAPM Midpoint	11.1%
Risk Premium Analysis	**Indicated Cost**
Utility Debt + Risk Premium	
Risk Premium (6.5% + 4.3%)	10.8%
Ibbotson Risk Premium Analysis	
Geometric Risk Premium (6.5% + 4.5%)	11.0%
Arithmetic Risk Premium (6.5% + 6.1%)	12.6%
Comparable Group ROE	10.75%
TEP ROE with Hypothetical Capital Structure	10.75%
TEP ROE with Actual Capital Structure	11.75%

Q. How should these results be interpreted to determine the fair cost of equity for TEP?

A. Caution should be exercised in interpreting the basic quantitative, because they are based on recent historically low points in the interest rate cycle. Under such conditions,

economic projections should also be considered. Continuing economic growth and higher expected interest rates show that less weight should be given to recent economic history. Additionally, use of a lower DCF range would fail to recognize the ongoing risks and uncertainties that continue to exist in the electric utility industry business as well as the uncertainties TEP is currently facing. From this perspective, TEP's cost of equity is in the range of 10.75 percent to 11.75 percent. The lower end of this range is appropriate if the Company's proposed capital structure is adopted, since that capital structure is more consistent with a low investment-grade credit rating. The upper end of the range is appropriate if the Company's actual test year capital structure is used. The higher required ROE associated with the Company's actual capital structure is consistent with the Commission's prior findings and with TEP's non-investment grade corporate bond rating. Use of the proposed capital structure recognizes the efforts the Company is making to improve its financial condition and will provide customers the benefit, in terms of a lower rate of return, that will result from those efforts.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT

SCH-1

Tucson Electric Power Company

Non-Investment Grade Spread Analysis

	Moody's Baa Public Utility Avg	(1) Empire District Sr Nts, 5.80%, 2035, BB+		(2) Southern Nat Gas (EP Corp) Nt, 8.0%, 2032, B+		(3) TN Gas Pipeline (EP Corp) Deb, 7.625%, 2037, B+	
		YTM	Diff	YTM	Diff	YTM	Diff
Apr-06	6.54%	n/a	n/a	7.16%	0.62%	7.25%	0.71%
May-06	6.59%	n/a	n/a	7.41%	0.82%	7.50%	0.91%
Jun-06	6.61%	n/a	n/a	7.55%	0.94%	7.55%	0.94%
Jul-06	6.61%	7.58%	0.97%	7.76%	1.15%	7.80%	1.19%
Aug-06	6.43%	7.39%	0.96%	7.58%	1.15%	7.63%	1.20%
Sep-06	6.26%	7.19%	0.93%	7.31%	1.05%	7.36%	1.10%
Oct-06	6.24%	7.05%	0.81%	7.09%	0.85%	7.16%	0.92%
Nov-06	6.04%	7.07%	1.03%	7.06%	1.02%	7.16%	1.12%
Dec-06	6.05%	6.85%	0.80%	6.60%	0.55%	6.65%	0.60%
Jan-07	6.16%	7.09%	0.93%	6.60%	0.44%	6.66%	0.50%
Feb-07	6.10%	7.21%	1.11%	6.68%	0.58%	6.74%	0.64%
Mar-07	6.10%	6.98%	0.88%	6.28%	0.18%	6.28%	0.18%
Average Spread			0.94%		0.78%		0.83%
Years to Maturity			28		25		30

		(4) El Paso Nat Gas (EP Corp) Nt, 8.375%, 2032, B+		(5) Chesapeake Energy Sr Nts, 6.875%, 2020, BB		(6) NW Pipeline (Williams Cos) Deb, 7.125%, 2025, BB-	
		YTM	Diff	YTM	Diff	YTM	Diff
Apr-06	6.54%	7.24%	0.70%	n/a	n/a	n/a	n/a
May-06	6.59%	7.49%	0.90%	n/a	n/a	n/a	n/a
Jun-06	6.61%	7.57%	0.96%	n/a	n/a	n/a	n/a
Jul-06	6.61%	7.92%	1.31%	n/a	n/a	7.60%	0.99%
Aug-06	6.43%	7.63%	1.20%	n/a	n/a	7.43%	1.00%
Sep-06	6.26%	7.36%	1.10%	7.55%	1.29%	7.21%	0.95%
Oct-06	6.24%	7.14%	0.90%	7.53%	1.29%	7.07%	0.83%
Nov-06	6.04%	7.16%	1.12%	7.53%	1.49%	7.06%	1.02%
Dec-06	6.05%	6.72%	0.67%	7.36%	1.31%	6.75%	0.70%
Jan-07	6.16%	6.65%	0.49%	7.07%	0.91%	7.00%	0.84%
Feb-07	6.10%	6.70%	0.60%	7.34%	1.24%	6.82%	0.72%
Mar-07	6.10%	6.30%	0.20%	6.85%	0.75%	6.43%	0.33%
Average Spread			0.85%		1.18%		0.82%
Years to Maturity			25		13		18

Average Spread **0.90%**

Source: S&P Bond Guide, Mergent Bond Record

Tucson Electric Power Company

Non-Investment Grade Spread Analysis

	(1) Moody's	(2) CSFB	(3) Reuters
2003	193	306	620
2004	81	181	144
2005	91	145	42
2006	67	110	151
2007 to date	57	88	159
Average	98	166	223

Notes:

(1) From "Median Spreads History for Bonds with 10 Year(s) Duration" shown in "Moody's Data" tab;
Non-investment grade spread is difference between Ba and Baa spreads;
Annual results calculated as average of monthly data;
2007 data through April.

(2) From data shown in "CSFB Data" tab;
Non-investment grade spread is difference between BB and UTILITY;BBB spreads;
Annual results calculated as average of weekly data;
2007 data through April 26.

(3) From "Reuters Corporate Spreads for Utilities" shown in "Reuters Data" tab;
Non-investment grade spread is difference between Ba2/BB and Baa2/BBB spreads;
Annual results as of last business day of year;
2007 data as of April 30.

EXHIBIT

SCH-2

Tucson Electric Power Company

Comparable Company Capital Structures

		YE 2006 Capital Structure			*Value Line* 3-5 Year Estimated Capital Structure		
	Company	Common Equity Ratio	Long-Term Debt Ratio	Preferred Stock Ratio	Common Equity Ratio	Long-Term Debt Ratio	Preferred Stock Ratio
1	ALLETE	64.9%	35.1%	0.0%	59.0%	41.0%	0.0%
2	Alliant Energy Co.	62.9%	31.4%	5.7%	52.5%	43.5%	4.0%
3	Ameren	53.0%	46.0%	1.0%	53.5%	45.0%	1.5%
4	American Elec. Pwr.	43.0%	56.7%	0.3%	43.0%	57.0%	0.0%
5	CH Energy Group	58.8%	38.8%	2.4%	48.0%	50.0%	2.0%
6	Cent. Vermont P.S.	56.5%	39.5%	4.0%	60.0%	37.0%	3.0%
7	Cleco Corporation	57.5%	41.0%	1.5%	48.0%	51.5%	0.5%
8	Con. Edison	49.0%	49.5%	1.5%	50.5%	48.5%	1.0%
9	DTE Energy Co.	43.9%	56.1%	0.0%	43.0%	57.0%	0.0%
10	Empire District	50.5%	49.5%	0.0%	48.5%	51.5%	0.0%
11	Energy East Corp.	43.5%	56.5%	0.0%	45.0%	54.5%	0.5%
12	FirstEnergy	51.3%	48.7%	0.0%	52.5%	47.5%	0.0%
13	Hawaiian Electric	48.6%	49.9%	1.5%	50.0%	48.5%	1.5%
14	IDACORP	54.8%	45.2%	0.0%	52.0%	48.0%	0.0%
15	MGE Energy, Inc.	60.5%	39.5%	0.0%	61.0%	39.0%	0.0%
16	NiSource Inc.	49.3%	50.7%	0.0%	52.5%	47.5%	0.0%
17	NSTAR	38.5%	60.5%	1.0%	54.0%	45.0%	1.0%
18	PNM Resources	48.8%	50.9%	0.3%	52.0%	47.5%	0.5%
19	Pinnacle West	51.6%	48.4%	0.0%	51.0%	49.0%	0.0%
20	PPL Corporation	42.2%	55.4%	2.4%	48.5%	49.5%	2.0%
21	Progress Energy	48.5%	51.0%	0.5%	49.5%	50.0%	0.5%
22	Puget Energy, Inc.	44.4%	55.5%	0.1%	48.5%	51.5%	0.0%
23	SCANA Corp.	47.2%	50.9%	1.9%	49.0%	49.5%	1.5%
24	Southern Co.	44.0%	53.5%	2.5%	42.5%	56.0%	1.5%
25	Teco Energy, Inc.	35.0%	65.0%	0.0%	47.0%	53.0%	0.0%
26	UIL Holdings Co.	54.0%	46.0%	0.0%	50.5%	49.5%	0.0%
27	Vectren Corp.	49.3%	50.7%	0.0%	51.5%	48.5%	0.0%
28	Xcel Energy Inc.	47.0%	52.1%	0.9%	46.5%	52.5%	1.0%
	Average	49.9%	49.1%	1.0%	50.3%	48.9%	0.8%

Source: Value Line Investment Survey, Electric Utility (East), Mar 2, 2007; (Central), Mar 30, 2007; (West), May 11, 2007.

Tucson Electric Power Company

Comparable Group Fundamental Characteristics

No.	Company	(1) % Regulated Revenue	(2) Credit Rating S&P	(2) Credit Rating Moody's	(3) S&P Business Profile	(4) Value Line Data Beta	(4) Value Line Data 2010-2012 Earned ROE
1	ALLETE	83.3%	A	Baa1	5	0.90	12.0%
2	Alliant Energy Co.	91.6%	A-	A2	6	0.95	9.5%
3	Ameren	100.0%	BBB	Baa1	6	0.75	9.0%
4	American Elec. Pwr.	94.9%	BBB	Baa1	6	1.35	12.5%
5	CH Energy Group	66.4%	A	A	3	0.85	8.5%
6	Cent. Vermont P.S.	100.0%	BBB	NR	6	0.70	8.5%
7	Cleco Corporation	96.3%	BBB	Baa1	6	1.30	10.0%
8	Con. Edison	78.1%	A	A1	2	0.75	9.0%
9	DTE Energy Co.	73.0%	BBB+	A3	6	0.75	9.5%
10	Empire District	99.1%	BBB+	Baa1	6	0.85	11.0%
11	Energy East Corp.	90.2%	BBB+	A3	3	0.95	9.5%
12	FirstEnergy	87.0%	BBB	Baa1	6	0.85	13.5%
13	Hawaiian Electric	83.5%	BBB	Baa2	6	0.75	12.0%
14	IDACORP	68.7%	A-	A-	5	1.05	7.5%
15	MGE Energy, Inc.	99.3%	AA-	Aa3	4	0.80	10.5%
16	NiSource Inc.	73.3%	BBB	Baa2	4	0.95	8.0%
17	NSTAR	95.9%	A+	A1	1	0.80	15.0%
18	PNM Resources	100.0%	BBB	Baa2	6	0.95	7.5%
19	Pinnacle West	77.5%	BBB-	Baa2	6	1.00	8.5%
20	PPL Corporation	66.3%	A-	A-	7	0.95	21.5%
21	Progress Energy	91.1%	BBB	A3	6	0.90	9.0%
22	Puget Energy, Inc.	99.7%	BBB	Baa2	4	0.85	9.5%
23	SCANA Corp.	68.7%	A-	A+	4	0.85	11.0%
24	Southern Co.	82.2%	A	A2	4	0.70	13.0%
25	Teco Energy, Inc.	77.2%	BBB-	Baa2	5	1.05	12.0%
26	UIL Holdings Co.	100.0%	NR	Baa2	n/a	0.95	8.0%
27	Vectren Corp.	81.0%	A	A3	3	0.95	11.0%
28	Xcel Energy Inc.	99.2%	BBB+	A3	5	0.90	10.5%
	Average	86.6%	A-/BBB+	A3	4.9	0.91	10.6%

Sources:
(1) Most recent company 10-Ks.
(2) AUS Utility Reports, Apr 2007.
(3) "U.S. Utility and Power Ranking List," Standard & Poor's, May 26, 2006.
(4) Value Line Investment Survey, Electric Utility (East), Mar 2, 2007; (Central), Mar 30, 2007; (West), May 11, 2007.

EXHIBIT

SCH-3

Tucson Electric Power Company

Capital Spending Relative to Net Plant

($millions unless otherwise noted)

No.	Reference Company	2006 Net Plant	Common Shares Outstanding 2007	2008	2009-2012	Capital Spending Per Share 2007	2008	2009-2012	Total Capital Spending 2007 -2012	Relative to Net Plant
1	ALLETE	922	30.9	31.3	32.5	5.80	5.75	5.50	1,074	116.5%
2	Alliant Energy Co.	4,945	109.5	110.3	113.0	4.90	5.30	5.30	3,517	71.1%
3	Ameren	14,095	208.6	210.6	216.6	9.10	9.00	5.55	8,602	61.0%
4	American Elec. Pwr.	26,781	398.5	400.0	405.0	10.10	7.80	7.50	19,295	72.0%
5	CH Energy Group	827	15.8	15.8	15.0	5.85	5.40	5.25	492	59.5%
6	Cent. Vermont P.S.	320	10.3	10.4	10.7	2.45	2.40	2.35	151	47.1%
7	Cleco Corporation	1,305	59.0	60.0	63.0	8.80	6.15	1.75	1,329	101.9%
8	Con. Edison	18,290	270.0	272.0	278.0	6.80	6.15	5.40	9,514	52.0%
9	DTE Energy Co.	11,451	176.0	172.0	168.0	7.95	8.15	8.25	8,345	72.9%
10	Empire District	1,025	31.3	32.8	33.0	5.90	6.20	3.00	784	76.5%
11	Energy East Corp.	5,935	147.8	147.8	147.8	2.70	2.60	2.50	2,261	38.1%
12	FirstEnergy	14,667	305.0	305.0	305.0	5.50	6.40	4.50	9,120	62.2%
13	Hawaiian Electric	2,648	83.5	85.5	87.0	2.80	3.55	2.25	1,320	49.9%
14	IDACORP	2,419	44.3	46.3	47.5	6.95	6.15	5.25	1,590	65.7%
15	MGE Energy, Inc.	675	20.7	20.7	20.7	4.00	4.00	4.00	497	73.6%
16	NiSource Inc.	9,695	274.0	274.5	276.0	2.90	2.55	2.25	3,979	41.0%
17	NSTAR	3,860	106.8	106.8	106.8	3.75	3.15	3.00	2,019	52.3%
18	PNM Resources	3,762	77.0	80.0	80.0	3.90	3.75	3.75	1,800	47.9%
19	Pinnacle West	7,882	100.0	100.0	100.0	8.00	8.00	8.00	4,800	60.9%
20	PPL Corporation	12,069	386.0	387.0	375.0	4.50	3.60	3.50	8,380	69.4%
21	Progress Energy	15,160	256.0	258.0	263.0	6.75	7.35	6.45	10,410	68.7%
22	Puget Energy, Inc.	5,181	117.0	117.8	124.3	4.55	5.30	5.25	3,766	72.7%
23	SCANA Corp.	7,004	117.0	117.0	117.0	6.40	7.45	5.25	4,077	58.2%
24	Southern Co.	31,050	765.0	783.0	805.0	5.10	5.75	4.25	22,089	71.1%
25	Teco Energy, Inc.	4,767	210.5	211.0	211.0	2.40	1.80	1.75	2,362	49.6%
26	UIL Holdings Co.	625	25.0	25.2	25.8	4.80	4.75	3.90	642	102.7%
27	Vectren Corp.	2,386	78.2	78.4	81.0	4.55	5.55	3.35	1,876	78.7%
28	Xcel Energy Inc.	15,549	427.0	429.0	435.0	4.45	4.45	4.00	10,769	69.3%
	Average									**66.5%**
	Tucson Electric Power*	1,682							1,349	**80.2%**

Source: Value Line Investment Survey, Electric Utility (East), Mar 2, 2007; (Central), Mar 30, 2007; (West), Feb 9, 2007.

*TEP Net Plant data from 2006 10-K as of December 31, 2006;
TEP Total Capital Spending 2007-2011 data from 2006 10-K; 2012 data from Company financial forecast;
TEP Capital Spending does not include spending for any new generating facilities. As such, it likely understates actual capital spending by a significant amount.

EXHIBIT

SCH-4

Tucson Electric Power
Historical Capital Market Costs

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Prime Rate	8.4%	8.4%	8.0%	9.2%	6.9%	4.7%	4.1%	4.3%	6.2%	8.0%
Consumer Price Index	2.3%	1.6%	2.2%	3.4%	2.8%	1.6%	2.3%	2.7%	3.4%	3.3%
Long-Term Treasuries	6.6%	5.6%	5.9%	5.9%	5.5%	5.4%	5.0%	5.1%	4.7%	5.0%
Moody's Avg Utility Debt	7.6%	7.0%	7.6%	8.1%	7.7%	7.5%	6.6%	6.2%	5.7%	6.1%
Moody's A Utility Debt	7.6%	7.0%	7.6%	8.2%	7.8%	7.4%	6.6%	6.2%	5.7%	6.1%

SOURCES:
Prime Interest Rate - Federal Reserve Bank of St. Louis website
Consumer Price Index - Federal Reserve Bank of St. Louis website
Long-Term Treasuries - Federal Reserve Bank of St. Louis website
Moody's Average Utility Debt - Moody's (Mergent) Bond Record
Moody's A Utility Debt - Moody's (Mergent) Bond Record

Tucson Electric Power
Long-Term Interest Rate Trends

Month	Baa Utility Rates	Average Utility Rates	Long-Term Treasury Rates	10-Year Treasury Rates
Jun-05	5.70%	5.39%	4.35%	4.00%
Jul-05	5.81%	5.50%	4.48%	4.18%
Aug-05	5.80%	5.51%	4.53%	4.26%
Sep-05	5.83%	5.54%	4.51%	4.20%
Oct-05	6.08%	5.79%	4.74%	4.46%
Nov-05	6.19%	5.88%	4.83%	4.54%
Dec-05	6.14%	5.83%	4.73%	4.47%
Jan-06	6.06%	5.77%	4.65%	4.42%
Feb-06	6.11%	5.83%	4.73%	4.57%
Mar-06	6.26%	5.98%	4.91%	4.72%
Apr-06	6.54%	6.28%	5.22%	4.99%
May-06	6.59%	6.39%	5.35%	5.11%
Jun-06	6.61%	6.39%	5.29%	5.11%
Jul-06	6.61%	6.37%	5.25%	5.09%
Aug-06	6.43%	6.20%	5.08%	4.88%
Sep-06	6.26%	6.03%	4.93%	4.72%
Oct-06	6.24%	6.01%	4.94%	4.73%
Nov-06	6.04%	5.82%	4.78%	4.60%
Dec-06	6.05%	5.83%	4.78%	4.56%
Jan-07	6.16%	5.97%	4.95%	4.76%
Feb-07	6.10%	5.91%	4.93%	4.72%
Mar-07	6.10%	5.87%	4.81%	4.56%

Sources: Mergent Bond Record (Utility Rates);
www.federalreserve.gov (Treasury Rates).

Exhibit SCH-4
3 of 3

Economic Indicators

Seasonally Adjusted Annual Rates — Dollar Figures in Billions

			Annual % Change				2006		E2007				E2008	
R2006	E2007	E2008	R2006	E2007	E2008		3Q	R4Q	1Q	2Q	3Q	4Q	1Q	2Q
						Gross Domestic Product								
$13,247.0	$13,904.0	$14,567.0	6.4	5.0	4.8	GDP (current dollars)	$13,323.0	$13,458.0	$13,663.0	$13,819.0	$13,987.0	$14,145.0	$14,310.0	$14,473.0
6.4	5.0	4.8	-	-	-	Annual rate of increase (%)	3.9	4.1	6.2	4.7	5.0	4.6	4.7	4.6
3.3	2.4	2.8	-	-	-	Annual rate of increase–real GDP (%)	2.0	2.5	1.9	2.8	2.9	2.7	2.6	2.8
2.9	2.5	1.9	-	-	-	Annual rate of increase–GDP deflator (%)	1.9	1.7	4.1	1.9	2.0	1.8	2.1	1.8
						***Components of Real GDP**								
$8,091.0	$8,345.0	$8,570.0	3.2	3.1	2.7	Personal consumption expenditures	$8,111.0	$8,196.0	$8,265.0	$8,314.0	$8,373.0	$8,427.0	$8,483.0	$8,536.0
3.2	3.1	2.7	-	-	-	% change	2.8	4.2	3.4	2.4	2.9	2.6	2.7	2.5
1,202.9	1,254.2	1,289.4	5.0	4.3	2.8	Durable goods	1,208.8	1,221.9	1,242.6	1,252.2	1,259.8	1,262.1	1,272.1	1,277.8
2,362.0	2,431.2	2,498.6	3.7	2.9	2.8	Nondurable goods	2,360.1	2,394.0	2,409.8	2,420.7	2,437.9	2,456.6	2,474.7	2,490.8
4,550.4	4,687.4	4,811.5	2.6	3.0	2.7	Services	4,566.6	4,605.2	4,641.0	4,670.0	4,703.5	4,735.3	4,764.5	4,795.2
1,312.4	1,360.7	1,423.3	7.2	3.7	4.6	Nonresidental fixed investment	1,334.2	1,323.7	1,327.3	1,352.7	1,370.8	1,392.1	1,405.1	1,415.7
7.2	3.7	4.6	-	-	-	% change	10.0	(3.1)	1.1	7.9	5.4	6.4	3.8	3.1
1,048.6	1,068.7	1,139.1	6.5	1.9	6.6	Producers durable equipment	1,060.7	1,047.8	1,042.7	1,058.6	1,076.7	1,096.6	1,114.4	1,129.1
572.5	488.4	470.9	(4.3)	(14.7)	(3.6)	Residental fixed investment	560.6	530.2	506.2	490.2	483.1	474.3	469.6	468.2
(4.3)	(14.7)	(3.6)	-	-	-	% change	(18.9)	(20.0)	(16.9)	(12.0)	(5.7)	(7.1)	(3.9)	(1.2)
43.2	23.8	28.9	-	-	-	Net change in business inventories	55.4	22.4	13.9	23.8	25.5	31.9	27.7	28.4
1,998.5	2,049.4	2,086.6	2.1	2.6	1.8	Gov't purchases of goods & services	1,999.4	2,016.1	2,025.1	2,044.2	2,058.2	2,070.0	2,078.0	2,084.6
742.0	761.4	775.3	2.0	2.6	1.8	Federal	738.9	747.2	747.5	760.4	767.0	770.7	773.6	775.5
1,256.4	1,287.8	1,311.1	2.1	2.5	1.8	State & local	1,260.3	1,268.7	1,277.3	1,283.7	1,291.1	1,299.2	1,304.3	1,308.9
(618.1)	(577.0)	(552.4)	-	-	-	Net exports	(628.8)	(582.6)	(573.9)	(578.9)	(576.5)	(578.7)	(568.5)	(554.9)
1,302.8	1,403.7	1,515.9	8.9	7.7	8.0	Exports	1,310.0	1,343.5	1,367.7	1,390.3	1,414.9	1,441.7	1,470.0	1,499.5
1,920.9	1,980.7	2,068.3	5.8	3.1	4.4	Imports	1,938.8	1,926.1	1,941.7	1,969.2	1,991.4	2,020.5	2,038.5	2,054.4
						****Income & Profits**								
$10,883.0	$11,498.0	$12,098.0	6.3	5.6	5.2	Personal income	$10,939.0	$11,065.0	$11,291.0	$11,421.0	$11,566.0	$11,712.0	$11,863.0	$12,017.0
9,523.0	10,034.0	10,560.0	5.4	5.4	5.3	Disposable personal income	9,577.0	9,679.0	9,848.0	9,969.0	10,095.0	10,223.0	10,349.0	10,494.0
(1.1)	(1.1)	(0.6)	-	-	-	Savings rate (%)	(1.4)	(1.2)	(1.2)	(1.2)	(1.0)	(0.8)	(0.8)	(0.6)
1,810.9	1,901.9	1,952.7	19.2	5.0	2.7	Corporate profits before taxes	1,854.0	1,837.6	1,898.7	1,890.9	1,905.4	1,912.6	1,931.4	1,943.0
1,336.0	1,405.7	1,446.9	19.4	5.2	2.9	Corporate profits after taxes	1,363.4	1,361.5	1,399.6	1,397.2	1,409.5	1,416.4	1,429.4	1,439.9
81.60	91.20	94.40	16.9	11.3	3.6	‡Earnings per share (S&P 500)	78.60	81.80	85.00	88.30	89.70	91.00	92.30	92.90
						†Prices & Interest Rates								
3.2	2.1	2.0	-	-	-	Consumer price index	3.1	(2.1)	4.1	2.8	1.3	1.6	2.4	1.9
4.7	5.0	4.5	-	-	-	Treasury bills	4.9	4.9	5.0	4.9	5.1	5.0	4.7	4.5
4.8	4.8	5.0	-	-	-	10-yr notes	4.9	4.6	4.7	4.7	4.8	4.9	4.9	4.9
4.9	4.9	5.2	-	-	-	30-yr bonds	5.0	4.7	4.8	4.8	5.0	5.1	5.0	5.1
5.6	5.4	5.8	-	-	-	New issue rate–corporate bonds	5.7	5.4	5.3	5.3	5.5	5.6	5.6	5.6
						Other Key Indicators								
1,820.0	1,500.0	1,560.0	(12.4)	(17.7)	4.5	Housing starts (1,000 units SAAR)	1,710.0	1,560.0	1,490.0	1,480.0	1,490.0	1,520.0	1,520.0	1,550.0
16.5	16.6	16.7	(2.6)	0.4	0.9	Auto & truck sales (1,000,000 units)	16.6	16.3	16.5	16.5	16.6	16.6	16.7	16.6
4.6	4.7	4.9	-	-	-	Unemployment rate (%)	4.7	4.5	4.5	4.6	4.7	4.8	4.9	4.9
(1.4)	(2.5)	(4.7)	-	-	-	§U.S. dollar	(2.1)	(0.7)	1.5	(5.1)	(3.4)	(5.0)	(6.0)	(4.1)

Note: Annual changes are from prior year and quarterly changes are from prior quarter. Figures may not add to totals because of rounding. A–Advance data. P–Preliminary. E–Estimated. R–Revised. *1996 Chain-weighted dollars. **Current dollars. ‡Trailing 4 quarters. †Average for period. §Quarterly % changes at quarterly rates. This forecast prepared by Standard & Poor's.

EXHIBIT

SCH-5

Tucson Electric Power Company

Comparison of Analysts' Growth Rates

2002 to 2007

No.	Company	Value Line Earnings 2002	Value Line Earnings 2007	% Points Decline
1	ALLETE	10.5%	10.5%	
2	Alliant Energy Co.	6.0%	5.0%	
3	Ameren	3.0%	1.0%	
4	American Elec. Pwr.	8.0%	7.0%	
5	CH Energy Group	1.5%	1.0%	
6	Cent. Vermont P.S.	12.0%	10.5%	
7	Cleco Corporation	6.5%	4.0%	
8	Con. Edison	2.5%	3.0%	
9	DTE Energy Co.	8.5%	4.0%	
10	Empire District	9.5%	10.0%	
11	Energy East Corp.	3.0%	3.0%	
12	FirstEnergy	NA	12.0%	
13	Hawaiian Electric	3.5%	4.0%	
14	IDACORP	NA	2.5%	
15	MGE Energy, Inc.	NA	6.0%	
16	NiSource Inc.	NA	5.5%	
17	NSTAR	4.5%	7.5%	
18	PNM Resources	2.5%	4.5%	
19	Pinnacle West	4.0%	3.5%	
20	PPL Corporation	7.0%	10.5%	
21	Progress Energy	NA	NA	
22	Puget Energy, Inc.	2.0%	6.0%	
23	SCANA Corp.	7.0%	3.0%	
24	Southern Co.	7.0%	3.0%	
25	Teco Energy, Inc.	6.0%	NA	
26	UIL Holdings Co.	2.5%	6.0%	
27	Vectren Corp.	11.5%	3.0%	
28	Xcel Energy Inc.	5.5%	5.5%	
	Average	5.83%	5.44%	0.38%

No.	Company	Value Line "br" 2002	Value Line "br" 2007	% Points Decline
1	ALLETE	8.7%	6.2%	
2	Alliant Energy Co.	3.1%	4.5%	
3	Ameren	3.4%	1.8%	
4	American Elec. Pwr.	6.6%	5.7%	
5	CH Energy Group	3.3%	2.3%	
6	Cent. Vermont P.S.	5.4%	4.3%	
7	Cleco Corporation	6.6%	3.1%	
8	Con. Edison	3.7%	2.4%	
9	DTE Energy Co.	6.8%	2.9%	
10	Empire District	3.0%	3.9%	
11	Energy East Corp.	6.0%	2.6%	
12	FirstEnergy	7.3%	7.1%	
13	Hawaiian Electric	3.0%	3.4%	
14	IDACORP	2.9%	3.5%	
15	MGE Energy, Inc.	NA	5.6%	
16	NiSource Inc.	5.8%	3.4%	
17	NSTAR	5.4%	6.3%	
18	PNM Resources	5.7%	3.1%	
19	Pinnacle West	5.6%	2.1%	
20	PPL Corporation	9.0%	9.7%	
21	Progress Energy	6.9%	1.9%	
22	Puget Energy, Inc.	4.1%	3.6%	
23	SCANA Corp.	5.1%	4.2%	
24	Southern Co.	4.7%	3.6%	
25	Teco Energy, Inc.	5.6%	4.3%	
26	UIL Holdings Co.	3.6%	1.3%	
27	Vectren Corp.	6.5%	3.1%	
28	Xcel Energy Inc.	5.3%	3.5%	
	Average	5.30%	3.90%	1.39%

Data Sources:

Electric: Value Line Investment Survey, Electric Utility (East), Mar 2, 2007 & Mar 7, 2002; (Central), Mar 30, 2007 & Apr 5, 2002; (West), May 11, 2007 & May 17, 2002.

EXHIBIT

SCH-6

Tucson Electric Power Company

GDP Growth Rate Forecast

	Nominal GDP	% Change	GDP Price Deflator	% Change	CPI	% Change
1947	244.2		15.5		22.3	
1948	269.2	10.2%	16.4	5.6%	24.1	7.7%
1949	267.3	-0.7%	16.4	-0.2%	23.8	-1.0%
1950	293.8	9.9%	16.5	1.0%	24.1	1.1%
1951	339.3	15.5%	17.7	7.2%	26.0	7.9%
1952	358.4	5.6%	18.0	1.7%	26.6	2.3%
1953	379.4	5.9%	18.2	1.2%	26.8	0.8%
1954	380.4	0.3%	18.4	1.0%	26.9	0.3%
1955	414.8	9.0%	18.7	1.8%	26.8	-0.2%
1956	437.5	5.5%	19.4	3.5%	27.2	1.4%
1957	461.1	5.4%	20.0	3.3%	28.1	3.4%
1958	467.2	1.3%	20.5	2.3%	28.9	2.7%
1959	506.6	8.4%	20.8	1.2%	29.2	1.0%
1960	526.4	3.9%	21.0	1.4%	29.6	1.5%
1961	544.7	3.5%	21.3	1.1%	29.9	1.0%
1962	585.6	7.5%	21.6	1.4%	30.3	1.2%
1963	617.8	5.5%	21.8	1.1%	30.6	1.3%
1964	663.6	7.4%	22.1	1.5%	31.0	1.3%
1965	719.1	8.4%	22.5	1.8%	31.6	1.6%
1966	787.8	9.5%	23.2	2.8%	32.5	3.0%
1967	832.6	5.7%	23.9	3.1%	33.4	2.7%
1968	910.0	9.3%	24.9	4.3%	34.8	4.2%
1969	984.6	8.2%	26.1	5.0%	36.7	5.4%
1970	1038.5	5.5%	27.5	5.3%	38.8	5.9%
1971	1127.1	8.5%	28.9	5.0%	40.5	4.2%
1972	1238.3	9.9%	30.2	4.3%	41.8	3.3%
1973	1382.7	11.7%	31.8	5.6%	44.4	6.3%
1974	1500.0	8.5%	34.7	9.1%	49.3	11.0%
1975	1638.3	9.2%	38.0	9.4%	53.8	9.1%
1976	1825.3	11.4%	40.2	5.8%	56.9	5.8%
1977	2030.9	11.3%	42.7	6.3%	60.6	6.5%
1978	2294.7	13.0%	45.7	7.0%	65.2	7.6%
1979	2563.3	11.7%	49.5	8.3%	72.6	11.3%
1980	2789.5	8.8%	54.0	9.1%	82.4	13.5%
1981	3128.4	12.1%	59.1	9.4%	90.9	10.4%
1982	3255.0	4.0%	62.7	6.1%	96.5	6.2%
1983	3536.7	8.7%	65.2	3.9%	99.6	3.2%
1984	3933.2	11.2%	67.6	3.8%	103.9	4.4%
1985	4220.3	7.3%	69.7	3.0%	107.6	3.5%
1986	4462.8	5.7%	71.2	2.2%	109.7	1.9%
1987	4739.5	6.2%	73.2	2.7%	113.6	3.6%
1988	5103.8	7.7%	75.7	3.4%	118.3	4.1%
1989	5484.4	7.5%	78.6	3.8%	123.9	4.8%
1990	5803.1	5.8%	81.6	3.9%	130.7	5.4%
1991	5995.9	3.3%	84.4	3.5%	136.2	4.2%
1992	6337.8	5.7%	86.4	2.3%	140.3	3.0%
1993	6657.4	5.0%	88.4	2.3%	144.5	3.0%
1994	7072.2	6.2%	90.3	2.1%	148.2	2.6%
1995	7397.7	4.6%	92.1	2.0%	152.4	2.8%
1996	7816.8	5.7%	93.8	1.9%	156.9	2.9%
1997	8304.3	6.2%	95.4	1.7%	160.5	2.3%
1998	8747.0	5.3%	96.5	1.1%	163.0	1.5%
1999	9268.4	6.0%	97.9	1.4%	166.6	2.2%
2000	9817.0	5.9%	100.0	2.2%	172.2	3.4%
2001	10128.0	3.2%	102.4	2.4%	177.0	2.8%
2002	10469.6	3.4%	104.2	1.7%	179.9	1.6%
2003	10960.8	4.7%	106.4	2.1%	184.0	2.3%
2004	11712.5	6.9%	109.4	2.8%	188.9	2.7%
2005	12455.8	6.3%	112.7	3.0%	195.3	3.4%
2006	13246.6	6.3%	116.0	2.9%	201.6	3.2%
10-Year Average		5.4%		2.1%		2.5%
20-Year Average		5.6%		2.5%		3.1%
30-Year Average		6.9%		3.6%		4.3%
40-Year Average		7.3%		4.1%		4.7%
50-Year Average		7.1%		3.7%		4.1%
59-Year Average		7.0%		3.5%		3.8%
Average of Periods		6.6%		3.3%		3.8%

Source: St. Louis Federal Reserve Bank, Economic Data - FRED II (www.research.stlouisfed.org).

EXHIBIT

SCH-7

Tucson Electric Power Company

Discounted Cash Flow Analysis
Summary Of DCF Model Results

Company	Traditional Constant Growth DCF Model	Constant Growth DCF Model Long-Term GDP Growth	Low Near-Term Growth Two-Stage Growth DCF Model
1 ALLETE	10.8%	10.4%	10.4%
2 Alliant Energy Co.	8.2%	9.8%	9.4%
3 Ameren	8.9%	11.5%	10.7%
4 American Elec. Pwr.	9.6%	10.2%	10.4%
5 CH Energy Group	7.7%	11.0%	10.4%
6 Cent. Vermont P.S.	10.4%	9.9%	9.3%
7 Cleco Corporation	9.8%	10.0%	10.3%
8 Con. Edison	8.6%	11.3%	10.6%
9 DTE Energy Co.	9.4%	11.2%	10.7%
10 Empire District	12.0%	11.8%	10.9%
11 Energy East Corp.	9.0%	11.7%	11.5%
12 FirstEnergy	11.2%	9.9%	9.7%
13 Hawaiian Electric	9.5%	11.3%	10.5%
14 IDACORP	7.9%	10.1%	9.4%
15 MGE Energy, Inc.	10.1%	10.7%	10.1%
16 NiSource Inc.	8.5%	10.4%	10.0%
17 NSTAR	10.8%	10.7%	10.7%
18 PNM Resources	8.6%	9.8%	9.7%
19 Pinnacle West	9.3%	11.2%	10.8%
20 PPL Corporation	13.1%	9.9%	10.7%
21 Progress Energy	9.3%	11.6%	10.8%
22 Puget Energy, Inc.	9.0%	10.5%	10.5%
23 SCANA Corp.	8.9%	10.9%	10.5%
24 Southern Co.	9.0%	11.1%	10.7%
25 Teco Energy, Inc.	10.1%	11.0%	10.5%
26 UIL Holdings Co.	9.4%	11.4%	10.6%
27 Vectren Corp.	8.9%	11.2%	10.8%
28 Xcel Energy Inc.	9.3%	10.7%	10.5%
GROUP AVERAGE	9.5%	10.8%	10.4%
GROUP MEDIAN	9.3%	10.8%	10.5%

Sources: Value Line Investment Survey, Electric Utility (East), Mar 2, 2007; (Central), Mar 30, 2007; (West), May 11, 2007.

NOTE: SEE PAGE 5 OF THIS SCHEDULE FOR FURTHER EXPLANATION OF EACH COLUMN.

Tucson Electric Power Company

Discounted Cash Flow Analysis

Traditional Constant Growth DCF Model

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Projected Growth Rate Analysis										
				Year 2011 "BR" Growth Rate Calculation										
Company	Recent Price(P0)	Next Year's Div(D1)	Dividend Yield	DPS	EPS	Retention Rate (B)	NBV	ROE (R)	B*R Growth	Zacks	Value Line	GDP Growth	Average Growth *(Cols 9-12)*	ROE K=Div Yld+G *(Cols 3+13)*
1 ALLETE	47.59	1.80	3.78%	2.20	4.00	45.00%	29.25	13.68%	6.15%	5.00%	10.50%	6.60%	7.06%	10.8%
2 Alliant Energy Co.	42.87	1.37	3.20%	1.49	2.75	45.82%	28.20	9.75%	4.47%	4.00%	5.00%	6.60%	5.02%	8.2%
3 Ameren	51.85	2.54	4.90%	2.54	3.20	20.63%	36.00	8.89%	1.83%	6.70%	1.00%	6.60%	4.03%	8.9%
4 American Elec. Pwr.	47.18	1.72	3.65%	2.20	4.00	45.00%	31.75	12.60%	5.67%	4.70%	7.00%	6.60%	5.99%	9.6%
5 CH Energy Group	48.58	2.16	4.45%	2.20	3.00	26.67%	35.25	8.51%	2.27%	NA	1.00%	6.60%	3.29%	7.7%
6 Cent. Vermont P.S.	27.75	0.92	3.32%	0.92	1.85	50.27%	21.75	8.51%	4.28%	NA	10.50%	6.60%	7.13%	10.4%
7 Cleco Corporation	26.53	0.90	3.39%	1.20	1.75	31.43%	18.00	9.72%	3.06%	12.00%	4.00%	6.60%	6.41%	9.8%
8 Con. Edison	50.11	2.34	4.67%	2.40	3.30	27.27%	37.00	8.92%	2.43%	3.50%	3.00%	6.60%	3.88%	8.6%
9 DTE Energy Co.	48.09	2.20	4.57%	2.40	3.50	31.43%	38.25	9.15%	2.88%	5.70%	4.00%	6.60%	4.79%	9.4%
10 Empire District	24.74	1.28	5.17%	1.28	2.00	36.00%	18.25	10.96%	3.95%	NA	10.00%	6.60%	6.85%	12.0%
11 Energy East Corp.	24.74	1.26	5.09%	1.45	2.00	27.50%	21.50	9.30%	2.56%	3.50%	3.00%	6.60%	3.91%	9.0%
12 FirstEnergy	65.21	2.15	3.30%	2.50	5.25	52.38%	38.75	13.55%	7.10%	6.00%	12.00%	6.60%	7.92%	11.2%
13 Hawaiian Electric	26.23	1.24	4.73%	1.24	1.75	29.14%	15.00	11.67%	3.40%	5.20%	4.00%	6.60%	4.80%	9.5%
14 IDACORP	34.53	1.20	3.48%	1.20	2.30	47.83%	31.20	7.37%	3.53%	5.00%	2.50%	6.60%	4.41%	7.9%
15 MGE Energy, Inc.	35.05	1.43	4.08%	1.47	2.55	42.35%	19.45	13.11%	5.55%	NA	6.00%	6.60%	6.05%	10.1%
16 NiSource Inc.	24.33	0.92	3.78%	1.00	1.75	42.86%	22.00	7.95%	3.41%	3.50%	5.50%	6.60%	4.75%	8.5%
17 NSTAR	34.91	1.43	4.10%	1.75	3.00	41.67%	19.75	15.19%	6.33%	6.30%	7.50%	6.60%	6.68%	10.8%
18 PNM Resources	31.62	1.02	3.23%	1.22	2.05	40.49%	26.95	7.61%	3.08%	7.30%	4.50%	6.60%	5.37%	8.6%
19 Pinnacle West	48.40	2.23	4.61%	2.47	3.30	25.15%	38.70	8.53%	2.14%	6.70%	3.50%	6.60%	4.74%	9.3%
20 PPL Corporation	39.97	1.30	3.25%	2.00	3.75	46.67%	18.00	20.83%	9.72%	12.50%	10.50%	6.60%	9.83%	13.1%
21 Progress Energy	50.09	2.48	4.95%	2.54	3.20	20.63%	34.45	9.29%	1.92%	4.40%	NA	6.60%	4.31%	9.3%
22 Puget Energy, Inc.	25.37	1.00	3.94%	1.20	2.00	40.00%	22.00	9.09%	3.64%	4.00%	6.00%	6.60%	5.06%	9.0%
23 SCANA Corp.	42.79	1.82	4.25%	2.00	3.25	38.46%	30.00	10.83%	4.17%	4.70%	3.00%	6.60%	4.62%	8.9%
24 Southern Co.	36.58	1.66	4.54%	1.80	2.50	28.00%	19.50	12.82%	3.59%	4.50%	3.00%	6.60%	4.42%	9.0%
25 Teco Energy, Inc.	17.18	0.76	4.42%	0.80	1.25	36.00%	10.50	11.90%	4.29%	6.00%	NA	6.60%	5.63%	10.1%
26 UIL Holdings Co.	36.12	1.73	4.79%	1.73	2.05	15.61%	24.95	8.22%	1.28%	N/A	6.00%	6.60%	4.63%	9.4%
27 Vectren Corp.	28.49	1.31	4.60%	1.43	2.00	28.50%	18.25	10.96%	3.12%	4.50%	3.00%	6.60%	4.31%	8.9%
28 Xcel Energy Inc.	24.14	0.99	4.10%	1.15	1.75	34.29%	17.00	10.29%	3.53%	5.00%	5.50%	6.60%	5.16%	9.3%
GROUP AVERAGE	37.18	1.54	4.15%						3.90%	5.68%	5.44%	6.60%	5.39%	9.5%
GROUP MEDIAN			4.18%											9.3%

Sources: Value Line Investment Survey, Electric Utility (East), Mar 2, 2007; (Central), Mar 30, 2007; (West), May 11, 2007.

NOTE: SEE PAGE 5 OF THIS SCHEDULE FOR FURTHER EXPLANATION OF EACH COLUMN.

Tucson Electric Power Company

Discounted Cash Flow Analysis
Constant Growth DCF Model
Long-Term GDP Growth

	(15)	(16)	(17)	(18)	(19)
Company	Recent Price(P0)	Next Year's Div(D1)	Dividend Yield	GDP Growth	ROE K=Div Yld+G *(Cols 17+18)*
1 ALLETE	47.59	1.80	3.78%	6.60%	10.4%
2 Alliant Energy Co.	42.87	1.37	3.20%	6.60%	9.8%
3 Ameren	51.85	2.54	4.90%	6.60%	11.5%
4 American Elec. Pwr.	47.18	1.72	3.65%	6.60%	10.2%
5 CH Energy Group	48.58	2.16	4.45%	6.60%	11.0%
6 Cent. Vermont P.S.	27.75	0.92	3.32%	6.60%	9.9%
7 Cleco Corporation	26.53	0.90	3.39%	6.60%	10.0%
8 Con. Edison	50.11	2.34	4.67%	6.60%	11.3%
9 DTE Energy Co.	48.09	2.20	4.57%	6.60%	11.2%
10 Empire District	24.74	1.28	5.17%	6.60%	11.8%
11 Energy East Corp.	24.74	1.26	5.09%	6.60%	11.7%
12 FirstEnergy	65.21	2.15	3.30%	6.60%	9.9%
13 Hawaiian Electric	26.23	1.24	4.73%	6.60%	11.3%
14 IDACORP	34.53	1.20	3.48%	6.60%	10.1%
15 MGE Energy, Inc.	35.05	1.43	4.08%	6.60%	10.7%
16 NiSource Inc.	24.33	0.92	3.78%	6.60%	10.4%
17 NSTAR	34.91	1.43	4.10%	6.60%	10.7%
18 PNM Resources	31.62	1.02	3.23%	6.60%	9.8%
19 Pinnacle West	48.40	2.23	4.61%	6.60%	11.2%
20 PPL Corporation	39.97	1.30	3.25%	6.60%	9.9%
21 Progress Energy	50.09	2.48	4.95%	6.60%	11.6%
22 Puget Energy, Inc.	25.37	1.00	3.94%	6.60%	10.5%
23 SCANA Corp.	42.79	1.82	4.25%	6.60%	10.9%
24 Southern Co.	36.58	1.66	4.54%	6.60%	11.1%
25 Teco Energy, Inc.	17.18	0.76	4.42%	6.60%	11.0%
26 UIL Holdings Co.	36.12	1.73	4.79%	6.60%	11.4%
27 Vectren Corp.	28.49	1.31	4.60%	6.60%	11.2%
28 Xcel Energy Inc.	24.14	0.99	4.10%	6.60%	10.7%
GROUP AVERAGE	37.18	1.54	4.15%	6.60%	10.8%
GROUP MEDIAN			4.18%		10.8%

Sources: Value Line Investment Survey, Electric Utility (East), Mar 2, 2007; (Central), Mar 30, 2007; (West), May 11, 2007.

NOTE: SEE PAGE 5 OF THIS SCHEDULE FOR FURTHER EXPLANATION OF EACH COLUMN.

Tucson Electric Power Company

Discounted Cash Flow Analysis
Low Near-Term Growth
Two-Stage Growth DCF Model

	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)
				CASH FLOWS							
Company	Next Year's Div	2011 Div	Annual Change to 2011	Recent Price	Year 1 Div	Year 2 Div	Year 3 Div	Year 4 Div	Year 5 Div	Year 5-150 Div Growth	ROE=Internal Rate of Return *(Yrs 0-150)*
1 ALLETE	1.80	2.20	0.13	47.59	1.80	1.93	2.07	2.20	2.35	6.60%	10.4%
2 Alliant Energy Co.	1.37	1.49	0.04	42.87	1.37	1.41	1.45	1.49	1.59	6.60%	9.4%
3 Ameren	2.54	2.54	0.00	51.85	2.54	2.54	2.54	2.54	2.71	6.60%	10.7%
4 American Elec. Pwr.	1.72	2.20	0.16	47.18	1.72	1.88	2.04	2.20	2.35	6.60%	10.4%
5 CH Energy Group	2.16	2.20	0.01	48.58	2.16	2.17	2.19	2.20	2.35	6.60%	10.4%
6 Cent. Vermont P.S.	0.92	0.92	0.00	27.75	0.92	0.92	0.92	0.92	0.98	6.60%	9.3%
7 Cleco Corporation	0.90	1.20	0.10	26.53	0.90	1.00	1.10	1.20	1.28	6.60%	10.3%
8 Con. Edison	2.34	2.40	0.02	50.11	2.34	2.36	2.38	2.40	2.56	6.60%	10.6%
9 DTE Energy Co.	2.20	2.40	0.07	48.09	2.20	2.27	2.33	2.40	2.56	6.60%	10.7%
10 Empire District	1.28	1.28	0.00	24.74	1.28	1.28	1.28	1.28	1.36	6.60%	10.9%
11 Energy East Corp.	1.26	1.45	0.06	24.74	1.26	1.32	1.39	1.45	1.55	6.60%	11.5%
12 FirstEnergy	2.15	2.50	0.12	65.21	2.15	2.27	2.38	2.50	2.67	6.60%	9.7%
13 Hawaiian Electric	1.24	1.24	0.00	26.23	1.24	1.24	1.24	1.24	1.32	6.60%	10.5%
14 IDACORP	1.20	1.20	0.00	34.53	1.20	1.20	1.20	1.20	1.28	6.60%	9.4%
15 MGE Energy, Inc.	1.43	1.47	0.01	35.05	1.43	1.44	1.46	1.47	1.57	6.60%	10.1%
16 NiSource Inc.	0.92	1.00	0.03	24.33	0.92	0.95	0.97	1.00	1.07	6.60%	10.0%
17 NSTAR	1.43	1.75	0.11	34.91	1.43	1.54	1.64	1.75	1.87	6.60%	10.7%
18 PNM Resources	1.02	1.22	0.07	31.62	1.02	1.09	1.15	1.22	1.30	6.60%	9.7%
19 Pinnacle West	2.23	2.47	0.08	48.40	2.23	2.31	2.39	2.47	2.63	6.60%	10.8%
20 PPL Corporation	1.30	2.00	0.23	39.97	1.30	1.53	1.77	2.00	2.13	6.60%	10.7%
21 Progress Energy	2.48	2.54	0.02	50.09	2.48	2.50	2.52	2.54	2.71	6.60%	10.8%
22 Puget Energy, Inc.	1.00	1.20	0.07	25.37	1.00	1.07	1.13	1.20	1.28	6.60%	10.5%
23 SCANA Corp.	1.82	2.00	0.06	42.79	1.82	1.88	1.94	2.00	2.13	6.60%	10.5%
24 Southern Co.	1.66	1.80	0.05	36.58	1.66	1.71	1.75	1.80	1.92	6.60%	10.7%
25 Teco Energy, Inc.	0.76	0.80	0.01	17.18	0.76	0.77	0.79	0.80	0.85	6.60%	10.5%
26 UIL Holdings Co.	1.73	1.73	0.00	36.12	1.73	1.73	1.73	1.73	1.84	6.60%	10.6%
27 Vectren Corp.	1.31	1.43	0.04	28.49	1.31	1.35	1.39	1.43	1.52	6.60%	10.8%
28 Xcel Energy Inc.	0.99	1.15	0.05	24.14	0.99	1.04	1.10	1.15	1.23	6.60%	10.5%
GROUP AVERAGE											10.4%
GROUP MEDIAN											10.5%

Sources: Value Line Investment Survey, Electric Utility (East), Mar 2, 2007; (Central), Mar 30, 2007; (West), May 11, 2007.

NOTE: SEE PAGE 5 OF THIS SCHEDULE FOR FURTHER EXPLANATION OF EACH COLUMN.

Tucson Electric Power Company

Discounted Cash Flow Analysis

DCF Analysis Column Descriptions

Column 1: Three-month Average Price per Share (Feb 2007-Apr 2007)

Column 2: Estimated 2008 Dividends per Share from Value Line

Column 3: Column 2 Divided by Column 1

Column 4: Estimated 2011 Dividends per Share from Value Line

Column 5: Estimated 2011 Earnings per Share from Value Line

Column 6: One Minus (Column 4 Divided by Column 5)

Column 7: Estimated 2011 Net Book Value per Share from Value Line

Column 8: Column 5 Divided by Column 7

Column 9: Column 6 Multiplied by Column 8

Column 10: "Next 5 Years" Company Growth Estimate as Reported by Zacks.com

Column 11: "Est'd 04-06 to 10-12" Earnings Growth Reported by Value Line.

Column 12: Average of GDP Growth During the Last 10 year, 20 year, 30 year, 40 year, 50 year, and 59 year growth periods.

Column 13: Average of Columns 9-12

Column 14: Column 3 Plus Column 13

Column 15: See Column 1

Column 16: See Column 2

Column 17: Column 16 Divided by Column 15

Column 18: See Column 12

Column 19: Column 17 Plus Column 18

Column 20: See Column 2

Column 21: See Column 4

Column 22: (Column 21 Minus Column 20) Divided by Three

Column 23: See Column 1

Column 24: See Column 20

Column 25: Column 24 Plus Column 22

Column 26: Column 25 Plus Column 22

Column 27: Column 26 Plus Column 22

Column 28: Column 27 Increased by the Growth Rate Shown in Column 29

Column 29: See Column 12

Column 30: The Internal Rate of Return of the Cash Flows in Columns 23-28 along with the Dividends for the Years 6-150 Implied by the Growth Rates shown in Column 29

EXHIBIT

SCH-8

Tucson Electric Power Company

Capital Asset Pricing Model Analysis

Panel 1: Long-Term CAPM Analysis

Long-Term Bond Equivalent Yield[1]		Effective Yield	
5.01%		5.07%	

Risk-free Rate		Value Line Beta[2]		Long-Term Ibbotson Risk Premium[3]		Cost of Common Equity
5.07%	+	0.91	x	5.75%	=	10.31%

Panel 2: Short-Term CAPM Analysis

Short-Term Bond Equivalent Yield[1]		Effective Yield	
4.75%		4.89%	

Risk-free Rate		Value Line Beta[2]		Short-Term Ibbotson Risk Premium[3]		Cost of Common Equity
4.89%	+	0.91	x	7.60%	=	11.81%

Summary of Results

Long-Term CAPM Result	10.31%
Short-Term CAPM Result	11.81%
Midpoint CAPM Result	**11.06%**

Notes:

[1] Federal Reserve Bank of St. Louis website as of May 25, 2007; Long-Term rate is "30-Year Treasury Constant Maturity Rate;" Short-Term rate is "3-Month Treasury Bill: Secondary Market Rate."

[2] Average beta coefficient for 28-company comparable group, see Exhibit SCH-2, page 2.

[3] Ibbotson Associates 2007 Yearbook, page 31, average of Geometric and Arithmetic risk premiums; Long-Term risk premium is difference between "Large Company Stocks" and "Long-Term Government;" Short-Term risk premium is difference between "Large Company Stocks" and "U.S. Treasury Bills."

EXHIBIT

SCH-9

Tucson Electric Power Company

Risk Premium Analysis

	MOODY'S AVERAGE PUBLIC UTILITY BOND YIELD (1)	AUTHORIZED ELECTRIC RETURNS (2)	INDICATED RISK PREMIUM
1980	13.15%	14.23%	1.08%
1981	15.62%	15.22%	-0.40%
1982	15.33%	15.78%	0.45%
1983	13.31%	15.36%	2.05%
1984	14.03%	15.32%	1.29%
1985	12.29%	15.20%	2.91%
1986	9.46%	13.93%	4.47%
1987	9.98%	12.99%	3.01%
1988	10.45%	12.79%	2.34%
1989	9.66%	12.97%	3.31%
1990	9.76%	12.70%	2.94%
1991	9.21%	12.55%	3.34%
1992	8.57%	12.09%	3.52%
1993	7.56%	11.41%	3.85%
1994	8.30%	11.34%	3.04%
1995	7.91%	11.55%	3.64%
1996	7.74%	11.39%	3.65%
1997	7.63%	11.40%	3.77%
1998	7.00%	11.66%	4.66%
1999	7.55%	10.77%	3.22%
2000	8.14%	11.43%	3.29%
2001	7.72%	11.09%	3.37%
2002	7.53%	11.16%	3.63%
2003	6.61%	10.97%	4.36%
2004	6.20%	10.75%	4.55%
2005	5.67%	10.54%	4.87%
2006	6.08%	10.36%	4.28%
AVERAGE	9.35%	12.48%	3.13%

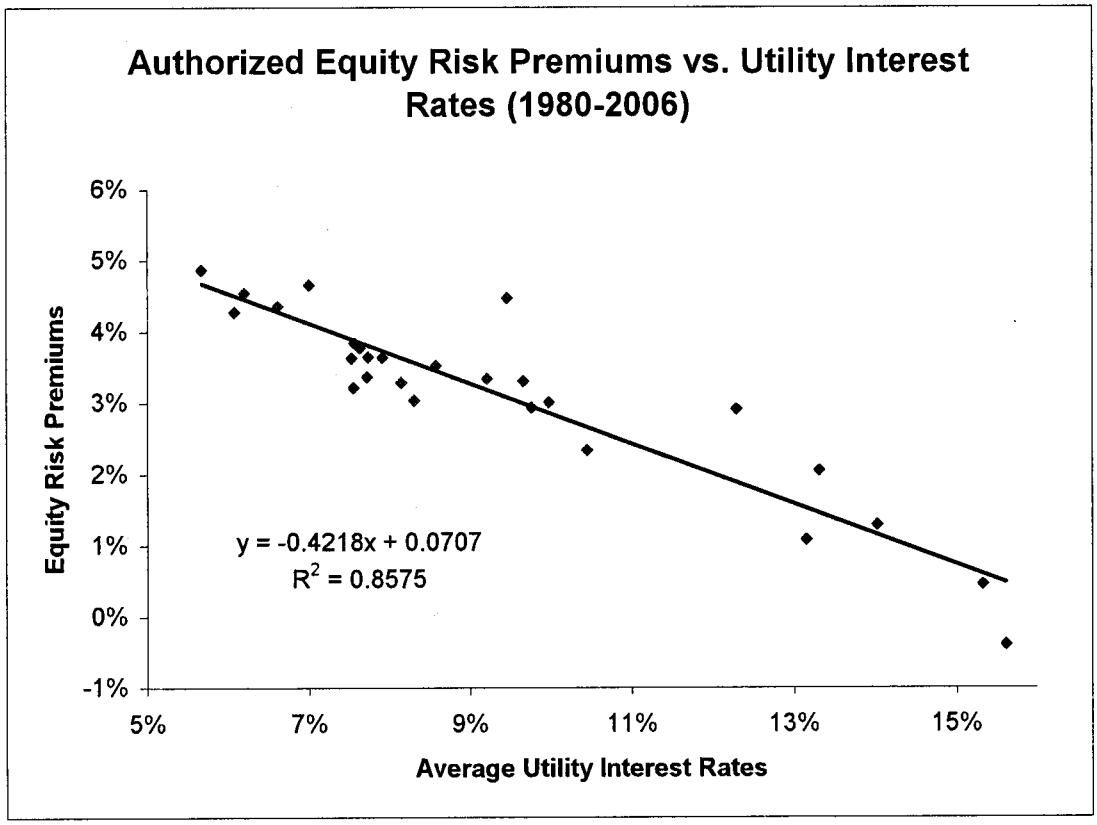
INDICATED COST OF EQUITY	
PROJECTED TRIPLE-B UTILITY BOND YIELD*	6.50%
MOODY'S AVG ANNUAL YIELD DURING STUDY	9.35%
INTEREST RATE DIFFERENCE	-2.85%
INTEREST RATE CHANGE COEFFICIENT	-42.18%
ADUSTMENT TO AVG RISK PREMIUM	1.20%
BASIC RISK PREMIUM	3.13%
INTEREST RATE ADJUSTMENT	1.20%
EQUITY RISK PREMIUM	4.33%
PROJECTED TRIPLE-B UTILITY BOND YIELD*	6.50%
INDICATED EQUITY RETURN	**10.83%**

Sources:

(1) Moody's Investors Service

(2) Regulatory Focus, Regulatory Research Associates, Inc.

*The projected triple-B bond yield is equal to the projected 30-year Treasury bond rate (5.2 percent) from S&P's Trends & Projections (Exhibit SCH-2, p. 3) plus 130 basis points. The average triple-B spread over Treasuries for 2006 was 133 basis points.

Tucson Electric Power Company

Risk Premium Analysis