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BEFORE THE ARIZONA CORPORATION COMMISSION

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AZ CORP COMMISSION
DOCKET CONTROL

Arizona Corporation Commission
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COMMISSIONERS
KRISTIN K. MAYES – Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

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-07-0402 **NOTICE OF FILING**

Tucson Electric Power Company ("TEP" or the "Company"), through undersigned counsel and pursuant to the Tucson Electric Power Company Proposed Rate Settlement Agreement, approved by Decision No. 70628 (December 1, 2008) ("2008 Settlement Agreement"), hereby files with the Arizona Corporation Commission ("Commission") its (i) Partial Requirements, Demand Response, and Bill Estimation tariffs, and (ii) Fuel Implementation Plan. In support of its filing, TEP states as follows:

I. TARIFFS.

Section 18.1 of the 2008 Settlement Agreement requires TEP to file within ninety (90) days of the effective date of the Commission's approval of the Agreement Partial Requirements, Interruptible, Demand Response, and Bill Estimation tariffs. TEP hereby files the required tariffs, as provided below, but, at the request of Arizonans for Electric Choice and Competition ("AECC") and the Residential Utility Consumer's Office ("RUCO"), seeks a 60-day extension on the filing of its two (2) Large Light and Power ("LLP") Interruptible tariffs. The 2008 Settlement Agreement directs that these LLP Interruptible tariffs be developed in consultation with Commission Staff and interested stakeholders; TEP has conferred with these parties. The parties are continuing to communicate on this matter, however, in an effort to reach mutually acceptable tariff terms; the filing extension, if granted, may result in the resolution of this matter. As previously indicated, AECC and RUCO support this request for an extension of the filing of the LLP Interruptible tariffs.

A. Partial Requirements.

On November 18, 2008, TEP filed its proposed Partial Requirements Service tariff ("PRS-N") for Commission approval. The Company has updated PRS-N to reflect a minor clarification of the applicability of partial requirements provisions to time-of-use service. TEP's revised PRS-N, with the clarifications redlined, is attached hereto as Exhibit A.

B. Demand Response.

TEP's Residential, General Service and Large General Service Demand Response tariffs are attached hereto as Exhibit B.

C. Bill Estimation.

TEP's Bill Estimation tariff is attached hereto as Exhibit C.

II. FUEL IMPLEMENTATION PLAN.

During the discovery phase of the TEP rate case, Docket Nos. E-01933A-05-0650 and E-01933A-07-0402, Commission Staff witness Emily S. Medine performed an audit of the Company's fuel and purchased power procurement practices. In her Direct Testimony, Ms. Medine offered recommendations for improvements to TEP's procurement practices and TEP agreed to implement those recommendations. In Section 19.1 of the 2008 Settlement Agreement, the Signatories agreed that TEP would file a fuel implementation plan within ninety (90) days of the effective date of the Commission order approving the 2008 Settlement Agreement. Attached hereto as Exhibit D is TEP's Fuel Implementation Plan.

III. CONCLUSION.

TEP requests that the Commission approve its Partial Requirements, Demand Response and Bill Estimation tariffs, and its Fuel Implementation Plan. The Company will file its LLP Interruptible tariffs with the Commission within sixty (60) days of the date of this filing.

RESPECTFULLY SUBMITTED this 2nd day of March 2009.

TUCSON ELECTRIC POWER COMPANY

By Michelle Livengood

Philip J. Dion
Michelle Livengood
Tucson Electric Power Company
One South Church Avenue, Ste 200
Tucson, Arizona 85701

and

Michael W. Patten
Roshka DeWulf & Patten, PLC
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004

Original and 15 copies of the foregoing filed this 2nd day of March 2009 with:

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

Copy of the foregoing hand-delivered/mailed this 2nd day of March 2009 to:

Brian Bozzo
Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copy of the foregoing emailed this 2nd day of March 2009 to:

Janet Wagner, Esq.
Robin Mitchell, Esq.
Chief Counsel, Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
jwagner@azcc.gov
rmitchell@azcc.gov
nscott@azcc.gov
rosorio@azcc.gov
mfinical@azcc.gov

Ernest G. Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
aigwe@azcc.gov
cbuck@azcc.gov
tford@azcc.gov
bkeene@azcc.gov

Jane Rodda, Esq.
Administrative Law Judge
Hearing Division
Arizona Corporation Commission
400 W. Congress
Tucson, Arizona 85701
jrodda@azcc.gov

Daniel Pozefsky, Chief Counsel
Residential Utility Consumer Office
1100 West Washington, Suite 220
Phoenix, Arizona 85007
dpozefsky@azruco.gov
brigsby@azruco.gov
egamble@azruco.gov

C. Webb Crockett
Patrick J. Black
FENNEMORE CRAIG, PC
3003 North Central Avenue, Suite 2600
Phoenix, Arizona 85012-2913
wcrockett@fclaw.com
pblack@fclaw.com
khiggins@energystrat.com

Michael Grant, Esq.
Gallagher & Kennedy
2575 East Camelback Road
Phoenix, Arizona 85016
mmg@gknet.com
gyaquinto@arizonaic.org

Peter Q. Nyce, Jr
General Attorney-Regulatory Office
Department of the Army
901 North Stuart Street
Arlington, Virginia 22203
peter.nyce@us.army.mil

Dan Neidlinger
Neidlinger & Associates
3020 North 17th Drive
Phoenix, Arizona 85015
dneid@cox.net

Nicolas J. Enoch
Lubin & Enoch, PC
349 North Fourth Avenue
Phoenix, Arizona 85003
Nicholas.enoch@azbar.org

Lawrence Robertson
P. O. Box 1448
Tubac, AZ 85646
tubaclawyer@aol.com

Thomas Mumaw
Barbara A. Klemstine
Arizona Public Service Company
P. O. Box 53999, Station 9708
Phoenix, Arizona 85072
Barbara.klemstine@aps.com
Meghan.grable@pinnaclewest.com

Robert J. Metli
Snell & Wilmer LLP
One Arizona Center
400 East Van Buren
Phoenix, AZ 85004
rmetli@swlaw.com

Christopher Hitchcock
Law Offices of Christopher Hitchcock
P. O. Box AT
Bisbee, Arizona 85603
lawyers@bisbeelaw.com

Timothy Hogan
Arizona Center for Law
in the Public Interest
202 East McDowell Road, Suite 153
Phoenix, Arizona 85004
thogan@aclpi.org

Jeff Schlegel
SWEEP Arizona Representative
1167 West Samalayuca Dr
Tucson, Arizona 85704
schlegelj@aol.com

David Berry
Western Resource Advocates
P. O. Box 1064
Scottsdale, Arizona 85252
azbluhill@aol.com

Michael L. Kurtz, Esq.
Kurt J. Boehm, Esq
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202
KBoehm@bkllawfirm.com
mkurtz@bkllawfirm.com

Greg Patterson
Arizona Competitive Power Alliance
916 West Adams, Suite 3
Phoenix, Arizona 85007
gpatterson3@cox.net

Cynthia Zwick
1940 E. Luke Avenue
Phoenix, Arizona 85016
czwick@azcaa.org

William P. Sullivan
Curtis, Goodwin, Sullivan,
Udall & Schwab, PLC
501 East Thomas Road
Phoenix, Arizona 85012
wsullivan@cgsuslaw.com

By: Mary Ippolito

Exhibit A

Pricing Plan PRS-N
Partial Requirements Service

AVAILABILITY

Available throughout the Company's entire electric service area to any Customer with a facility for the production of electricity on its premises using Renewable Resources [1], a Fuel Cell [2] or Combined Heat and Power (CHP) [3] to generate electricity, which is operated by or on behalf of the Customer, is intended to provide all or part of the Customer's electricity requirements, has a generating capacity less than or equal to 125% of the Customer's total connected load at the metered premise, or in the absence of load data, has capacity less than the Customer's electric service drop capacity, and is interconnected with and can operate in parallel and in phase with the Company's existing distribution system. Customer shall comply with all applicable federal, state, and local laws, regulations, ordinances and codes governing the production and/or sale of electricity.

For purposes of this Pricing Plan, the following notes and/or definitions apply:

[1] Renewable Resources means natural resources that can be replenished by natural process. Renewable Resources include biogas, biomass, geothermal, hydroelectric, solar, or wind.

[2] Fuel Cell means a device that converts the chemical energy of a fuel directly into electricity without intermediate combustion or thermal cycles. The source of the chemical reaction must be derived from Renewable Resources.

[3] Combined Heat and Power (CHP) also known as cogeneration means a system that generates electricity and useful thermal energy in a single integrated system such that the useful power output of the facility plus one-half the useful thermal energy output during any 12-month period must be no less than 42.5 percent of the total energy input of fuel to the facility.

CHARACTER OF SERVICE

The service shall be single- or three-phase, 60 Hertz, at one standard nominal voltage as mutually agreed and subject to availability at the point of delivery. Primary metering will be used by mutual agreement between the Company and the Customer.

RATE

Customer Charges shall be billed pursuant to the Customer's standard offer Pricing Plan otherwise applicable under full requirements of service.

Power sales and special services supplied by the Company to the Customer in order to meet the Customer's supplemental or interruptible electric requirements will be priced pursuant to the Customer's standard offer Pricing Plan otherwise applicable under full requirements service.

Non-Time-of-Use Rates: For Customers taking service under a Standard Retail Rate that is not a time-of-use rate, the Customer Supplied kWh shall be credited against the Company Supplied kWh. The Customer's monthly bill shall be based on this net kWh amount. Any monthly Excess Generation will be treated in accordance with the provisions outlined below.

Time-of-Use Rates: For Customers taking service under a Standard Retail Rate that is a time-of-use rate, the Customer Supplied kWh during on-peak hours shall be credited against the Company Supplied kWh during on-peak hours. All Customer Supplied kWh during off-peak hours shall be credited against the Company Supplied kWh during off-peak hours. And all Customer Supplied kWh during the shoulder hours shall be credited against the Company Supplied kWh during the shoulder hours. The Customer's monthly bill shall be based on this net kWh amount. Any monthly Excess Generation will be treated in accordance with the provisions outlined below.

EXCESS GENERATION
If for a billing month the Customer's generation facility's energy production exceeds the energy supplied by the Company, the Customer's bill for the next billing period shall be credited for the excess generation. That is, the excess kWh during the billing period shall be used to reduce the kWh supplied (not kW or kVA demand or customer/facilities charges) and billed by the Company during the following billing period. Customers taking service under a time-of-use rate who are to receive credit in a subsequent billing period for excess kWh generated shall receive such credit in the next billing period for the on-peak, shoulder, or off-peak periods in which the kWh were generated by the Customer. Time-of-Use Customer's taking service in the billing month of April shall receive a credit to summer on-peak and summer off-peak usage in the billing month of May for any winter on-peak and/or winter off-peak excess generation for April.

Each calendar year, for the customer bills produced in October (September usage) or a customer's "Final" bill - the Company shall credit the Customer for the balance of excess kWhs after netting. The payment for the purchase of the excess kWhs will be at the Company's applicable avoided cost, which for purposes of this pricing plan shall be the simple average of the hourly Market Cost of Comparable Conventional Generation (MCCCG) for the applicable year.

METERING
The Company will install a bi-directional meter at the point of delivery to the customer and meter at the point of output from each of the Customer's generators. At the Company's request a dedicated phone line will be provided by the customer to the metering to allow remote interegation of the meters at each site. If by mutal agreement between company and customer that a phone line is impractical or can not be provided - the customer will work with company to allow for the installation of equipment, on or with customer facilities or equipment to allow remote acces to each meter. Any additional cost of communication, such as but not limited too, cell phone service fees will be the responsibility of the customer.

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.

MARKET COST OF COMPARABLE CONVENTIONAL GENERATION
The Commission provided guidance on defining MCCCG in the context of its REST Rules and identified the MCCCG as "the Affected Utility's energy and capacity cost of producing or procuring the incremental electricity that would be avoided by the resources used to meet the Annual Renewable Energy Requirement, taking into account hourly, seasonal and long term supply and demand circumstances. Avoided costs include any avoided transmission and distribution costs and any avoided environmental compliance costs." R14-2-1801.11.

For purposes of calculating credits to the Customer for Excess Generation, the unit price paid shall be the simple average of the MCCCG over the 8,760 hours (8,784 in a leap year) hours in the forecasted year. The MCCCG in each hour is based on whether native load requirements will be met by internally owned or contracted generation resources or if market purchases will be required to meet native load requirements. The following table provides a description of the MCCCG methodology. The hourly MCCCG cost determination criteria is based on the Market Condition and Dispatch Type. This method of cost determination is very data intensive and will be calculated annually by running TEP's "Planning and Risk" modeling software, and the rate will be filed with the Commission by February 1 of each year and its applicability will concide with the next Purchased Power and Fuel Adjustment Clause ("PPFAC") rate effective period.

MCCCG Cost Determination Matrix

<table>
<tr><td rowspan="4">Market Condition and Dispatch Type</td><td>Selling to Market from In House Real and Contracted Generation Sources</td><td rowspan="2">MCCCG Cost Based on Incremental Production/Purchase Cost of Base Load Generation for that hour</td></tr>
<tr><td>No Market Transactions from/to In House and Contracted Generation Sources</td></tr>
<tr><td>Purchasing from Day Ahead Market, but not Spot Market, to meet Native Load Requirements</td><td>MCCCG Cost Based on Average Day Ahead Market Price of Purchased Power for that hour</td></tr>
<tr><td>Purchasing from Spot Market to meet Native Load Requirements</td><td>MCCCG Cost Based on Average Spot Market Price of Purchased Power for that hour</td></tr>
</table>

Incremental Production / Purchase of Base Load - The cost of the next kWh (incremental) amount of load that has to be provided by TEP generation sources and/or purchased power. This will be dependent on the season, month and time of day.

If Day Ahead Market or Spot Market purchases are being used to provide for reliability support capacity to meet native load requirements by freeing up in house or contracted generation resources for regulation or spinning reserve purposes for support of native load requirements, that would still represent a Market Purchase for purposes of determining which matrix box is applicable.

Exhibit B

Tucson Electric Power

A UniSource Energy Company

Pricing Plan R-70N-SP
Residential "Super Peak PowerShift™" Time-of-Use Program -- DRAFT

AVAILABILITY
Available throughout the Company's entire electric service 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, or auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

Customers must stay on this pricing plan for a minimum period of twelve (12) billing months. A Customer, at his/her discretion and after being served for at least twelve (12) billing months under this pricing plan, may opt to switch service to another applicable pricing plan.

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, Single Phase service and minimum bill $ 8.00 per billing month

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

Delivery Charge

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.095842	$0.053783	$0.046042
Next 3,000 kWh	$0.111303	$0.073783	$0.061503
Over 3,500 kWh	$0.131303	$0.093783	$0.081503

Summer TOU periods:

Weekdays except Memorial Day, Independence Day (July 4), and Labor Day. If Independence Day falls on Saturday, the Weekend schedule applies on the preceding Friday, July 3. If Independence Day falls on Sunday, the Weekend schedule applies on the following Monday, July 5.

On-Peak: Either: Version A: 2:00 p.m. to 3:00 p.m., or
Version B: 3:00 p.m. to 4:00 p.m., or
Version C: 4:00 p.m. to 5:00 p.m.; or
Version D: 5:00 p.m. to 6:00 p.m.

Shoulder-Peak: Either: Version A: 3:00 p.m. to 6:00 p.m., or
Version B: 2:00 p.m. to 3:00 p.m. and 4:00 p.m. to 6:00 p.m., or
Version C: 2:00 p.m. to 4:00 p.m. and 5:00 p.m. to 6:00 p.m., or
Version D: 2:00 p.m. to 5:00 p.m.

Off-Peak: 12:00 a.m. (midnight) to 2 p.m. and 6:00 p.m. to 12:00 a.m. (midnight)

Weekends (Saturday and Sunday), Memorial Day, Independence Day (or July 3 or July 5, under above conditions), and Labor Day.

On-Peak: *(There are no On-Peak weekend hours)*
Shoulder-Peak: *(There are no Shoulder-Peak weekend hours)*
Off-Peak: All hours.

The Version (i.e., A, B, C, or D) available to a specific customer shall be determined on the basis of a rule documented in this pricing plan's Plan of Administration. This rule helps promote load diversity, a beneficial result of a demand response program.

Delivery Charge

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.072706	$0.042706
Next 3,000 kWh	$0.089140	$0.059140
Over 3,500 kWh	$0.109140	$0.079140

Winter TOU periods:

Weekdays except Thanksgiving Day, Christmas Day, and New Years Day. If Christmas Day and New Years Day fall on Saturdays, the Weekend schedule applies on the preceding Fridays, December 24 and December 31. If Christmas Day and New Years Day fall on Sundays, the Weekend schedule applies on the following Mondays, December 26 and January 2.

On-Peak: 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: no shoulder peak periods in the winter.
Off-Peak: 12:00 a.m. (midnight) to 6:00 a.m., 10:00 a.m. to 5:00 p.m., and 9:00 p.m. to 12:00 a.m. (midnight)

Weekends (Saturday and Sunday), Thanksgiving Day, Christmas Day (or December 24 or December 26, under above conditions), and New Years Day (or December 31 or January 2, under above conditions).

On-Peak: *(There are no On-Peak weekend hours)*
Shoulder-Peak: *(There are no Shoulder-Peak weekend hours)*
Off-Peak: All hours.

Calculation of Tiered (Block) Usage by TOU Period:

Step 1: Calculate percent usage by TOU period.
Step 2: Calculate the kWh usage by tier (block).
Step 3: Multiply percent usage by TOU period by kWh usage by tier to obtain tiered usage by TOU period.
Example: A customer using 2,000 kWh in a month, with 20% peak usage, 25% shoulder usage, and 55% off-peak usage will have 100 kWh in peak 1st tier, 300 kWh in peak 2nd tier, 125 kWh in shoulder 1st tier, 375 kWh in shoulder 2nd tier, 275 kWh in off-peak 1st tier, and 825 kWh in off-peak 2nd tier.

Base Power Supply Charge

	Summer (May – October)	Winter (November - April)
On-Peak	$0.181956	$0.045063
Shoulder-Peak	$0.036656	N/A
Off-Peak	$0.020880	$0.026368

Purchased Power and Fuel Adjustment Clause ("PPFAC"): The Base Power Supply 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 billing month
Meter Reading	$0.80 per billing month
Billing & Collection	$3.29 per billing month
Customer Delivery	$2.40 per billing month

Energy Charges:

Delivery:
NOTE: While some delivery charges may be negative, the minimum total monthly bill (excluding services provided by third-party service providers), shall be zero. Negative charges reduce the total monthly bill, but are not permitted to create a negative bill, which would result the customer being paid (rather than paying) for TEP services.

Delivery Charge

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.026159	$0.003435	$0.002894
Next 3,000 kWh	$0.041620	$0.023435	$0.018355
Over 3,500 kWh	$0.061620	$0.043435	$0.038355

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.014093	$0.000980
Next 3,000 kWh	$0.030527	$0.017414
Over 3,500 kWh	$0.050527	$0.037414

Fixed Must-Run	$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 Capacity

	Summer (May – October)	Winter (November - April)
On-Peak	$0.055721	$0.044651
Shoulder-Peak	$0.036386	N/A
Off-Peak	$0.029186	$0.027764

Base Power Supply Charge

	Summer (May – October)	Winter (November - April)
On-Peak	$0.181956	$0.045063
Shoulder-Peak	$0.036656	N/A
Off-Peak	$0.020880	$0.026368

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 be in the future, 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.

A UniSource Energy Company

Pricing Plan GS-76N-SP
General Service "Super-Peak PowerShift™" Time-of-Use Program - DRAFT

AVAILABILITY
Available throughout the Company's entire electric service 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 pricing plan.

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

Customers must stay on this pricing plan for a minimum period of twelve (12) billing months. A Customer, at his/her discretion and after being served for at least twelve (12) billing months under this pricing plan, may opt to switch service to another applicable pricing plan.

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 and minimum bill	$ 9.00 per month
Customer Charge, Three Phase service and minimum bill	$15.00 per month

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

Delivery Charge

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.173608	$0.044281	$0.028845
Over 500 kWh	$0.212895	$0.083568	$0.068132

The Summer periods below apply to all summer days:

On-Peak: Either:
Version A: 2:00 p.m. to 3:00 p.m.;
Version B: 3:00 p.m. to 4:00 p.m.;
Version C: 4:00 p.m. to 5:00 p.m.; or
Version D: 5:00 p.m. to 6:00 p.m.

Shoulder-Peak: Either:
Version A: 3:00 p.m. to 6:00 p.m.;
Version B: 2:00 p.m. to 3:00 p.m. and 4:00 p.m. to 6:00 p.m.;
Version C: 2:00 p.m. to 4:00 p.m. and 5:00 p.m. to 6:00 p.m.; or
Version D: 2:00 p.m. to 5:00 p.m.

Off-Peak: 12:00 a.m. (midnight) to 2 p.m. and 6:00 p.m. to 12:00 a.m. (midnight)

The Version (i.e., A, B, C, or D) available to a specific customer shall be determined on the basis of a rule documented in this pricing plan's Plan of Administration. This rule helps promote load diversity, a beneficial result of a demand response program.

Delivery Charge

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.095613	$0.028844
Over 500 kWh	$0.134878	$0.068109

The Winter periods below apply to all winter days:

On-Peak 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: no shoulder peak periods in the winter.
Off-Peak: 12:00 a.m. (midnight) to 6:00 a.m., 10:00 a.m. to 5:00 p.m., and 9:00 p.m. to 12:00 a.m. (midnight)

Calculation of Tiered (Block) Usage by TOU Period:

Step 1: Calculate percent usage by TOU period.
Step 2: Calculate the kWh usage by tier (block).
Step 3: Multiply percent usage by TOU period by kWh usage by tier to obtain tiered usage by TOU period.
Example: A customer using 2,000 kWh in a month, with 20% peak usage, 25% shoulder usage, and 55% off-peak usage will have 100 kWh in peak 1st tier, 300 kWh in peak 2nd tier, 125 kWh in shoulder 1st tier, 375 kWh in shoulder 2nd tier, 275 kWh in off-peak 1st tier, and 825 kWh in off-peak 2nd tier.

Base Power Supply Charge

Summer On-Peak	$0.148600 per kWh
Summer Shoulder-Peak	$0.032000 per kWh
Summer Off-Peak	$0.022000 per kWh
Winter On-Peak	$0.032000 per kWh
Winter Off-Peak	$0.022000 per kWh

Purchased Power and Fuel Adjustment Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with Rider-1 PPFAC 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

A UniSource Energy Company

Pricing Plan GS-76N-SP
General Service "Super-Peak PowerShift™"
Time-of-Use Program - DRAFT

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 $6.00 per month for Three Phase Service.

Energy Charges (kWh):

Delivery Charge

SUMMER (May – October)	On-Peak	Shoulder-Peak	Off-Peak
First 500 kWh	$0.075174	$0.010847	$0.005411
Over 500 kWh	$0.114461	$0.050134	$0.044698

WINTER (November – April)	On-Peak	Off-Peak
First 500 kWh	$0.027179	$0.005410
Over 500 kWh	$0.066444	$0.044675

Generation Capacity

Summer On-Peak	$0.085343 per kWh
Summer Shoulder-Peak	$0.020343 per kWh
Summer Off-Peak	$0.010343 per kWh
Winter On-Peak	$0.055343 per kWh
Winter Off-Peak	$0.010343 per kWh

Fixed Must-Run	$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.

Base Power Supply Charge	
Summer On-Peak	$0.148600 per kWh
Summer Shoulder-Peak	$0.032000 per kWh
Summer Off-Peak	$0.022000 per kWh
Winter On-Peak	$0.032000 per kWh
Winter Off-Peak	$0.022000 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 be in the future, 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.

A UniSource Energy Company

Pricing Plan LGS-85N-SP
Large General Service "Super-Peak PowerShift™" Time-of-Use Program - DRAFT

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises. To all general power and lighting service unless otherwise addressed by specific rate schedules.

APPLICABILITY
When all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, standby, or auxiliary service. Service under this pricing plan will commence when the appropriate meter has been installed.

The minimum monthly billing demand hereunder is 200 kW.

Customers must stay on this pricing plan for a minimum period of twelve (12) billing months. A Customer, at his/her discretion and after being served for at least twelve (12) billing months under this pricing plan, may opt to switch service to another applicable pricing plan.

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.

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

BUNDLED STANDARD OFFER SERVICE

Customer Charge and minimum bill — $371.87 per month

Demand Charges (includes Generation Capacity):
- Summer Demand — $20.108 per kW
- Winter Demand — $15.326 per kW

Note: Demand Charges under LGS-85N-SP are not differentiated by time of day, only by season (summer/winter).

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

Delivery Charge

	Summer (May – October)	Winter (November - April)
On-Peak	$0.009204	$0.003068
Shoulder-Peak	$0.006136	N/A
Off-Peak	$0.003068	$0.000000

The Summer periods below apply on all days for consumption-based (kWh-based) charges.

On-Peak: Either: Version A: 2:00 p.m. to 3:00 p.m.;
Version B: 3:00 p.m. to 4:00 p.m.;
Version C: 4:00 p.m. to 5:00 p.m.; or
Version D: 5:00 p.m. to 6:00 p.m.

Shoulder-Peak: Either: Version A: 3:00 p.m. to 6:00 p.m.;
Version B: 2:00 p.m. to 3:00 p.m. and 4:00 p.m. to 6:00 p.m.;
Version C: 2:00 p.m. to 4:00 p.m. and 5:00 p.m. to 6:00 p.m.; or
Version D: 2:00 p.m. to 5:00 p.m.

Off-Peak: 12:00 a.m. (midnight) to 2 p.m. and 6:00 p.m. to 12:00 a.m. (midnight)

The Version (i.e., A, B, C, or D) available to a specific customer shall be determined on the basis of a rule documented in this pricing plan's Plan of Administration. This rule helps promote load diversity, a beneficial result of a demand response program.

The Winter periods below apply on all days for consumption-based (kWh-based) charges.

On-Peak: 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: no shoulder peak periods in the winter.
Off-Peak: 12:00 a.m. (midnight) to 6:00 a.m., 10:00 a.m. to 5:00 p.m., and 9:00 p.m. to 12:00 a.m. (midnight)

Base Power Supply Charge

	Summer (May – October)	Winter (November - April)
On-Peak	$0.168108	$0.036088
Shoulder-Peak	$0.033588	N/A
Off-Peak	$0.025299	$0.027799

Purchased Power and Fuel Adjustment Clause ("PPFAC"): The Base Power Supply 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.

SHOULDER CONSUMPTION (kWh) IN OCTOBER

Any shoulder consumption (kWh) remaining from October usage shall be billed at the summer shoulder price in following billing months.

BILLING DEMAND

The billing demand shall be specified in the contract, but shall not be less than 200 kW. Additionally, the billing demand shall not be less than 50.00% of the maximum billing demand in the preceding eleven months, unless otherwise specified in the contract.

Pricing Plan LGS-85N-SP
Large General Service "Super-Peak PowerShift™" Time-of-Use Program - DRAFT

PRIMARY SERVICE

The rates contained in this schedule reflect secondary service. Primary service shall be subject to a primary discount of 20.6 cents per kW per month (on the bundled rate, with the discount take from the unbundled kW delivery charge) on 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
Demand Charges ($/kW)	
Generation Capacity Charges ($/kW)	
Summer Demand	$ 8.560 per kW
Winter Demand	$ 6.560 per kW
Delivery Charges	
Summer Demand	$ 6.434 per kW
Winter Demand	$ 4.714 per kW
Fixed Must-Run Charges ($/kW)	
Summer Demand & Winter Demand	$ 0.629 per kW
System Benefits Charges ($/kW)	
Summer Demand & Winter Demand	$ 0.085 per kW
Transmission ($/kW)	
Summer Demand	$ 3.431 per kW
Winter Demand	$ 2.602 per kW
Transmission - Ancillary Services 1 - System Control & Dispatch	
Summer Demand	$ 0.047 per kW
Winter Demand	$ 0.036 per kW
Transmission - Ancillary Services 2 - Reactive Supply and Voltage Control	
Summer	$ 0.184 per kW
Winter Demand	$ 0.140 per kW
Transmission - Ancillary Services 3 - Regulation and Frequency Response	
Summer Demand	$ 0.178 per kW
Winter Demand	$ 0.134 per kW

Transmission - Ancillary Services 4 - Spinning Reserve Service	
Summer Demand	$ 0.482 per kW
Winter Demand	$ 0.366 per kW
Transmission - Ancillary Services 5 - Supplemental Reserve Service	
Summer Demand	$ 0.078 per kW
Winter Demand	$ 0.060 per kW

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

Energy Charges ($/kWh):

Delivery Charge

	Summer (May – October)	Winter (November - April)
On-Peak	$0.009204	$0.003068
Shoulder-Peak	$0.006136	N/A
Off-Peak	$0.003068	$0.000000

Base Power Supply Charge

	Summer (May – October)	Winter (November - April)
On-Peak	$0.168108	$0.036088
Shoulder-Peak	$0.033588	N/A
Off-Peak	$0.025299	$0.027799

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 be in the future, 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.

Exhibit C

Bill Estimation Methodologies

Tucson Electric Power Company ("TEP") regularly encounters situations in which TEP cannot obtain a complete and valid meter read. This could result from, among other reasons, the customer has not provided TEP access to the meter or has diverted energy, the meter is broken, or weather conditions have made it impossible to read the meter. No matter the cause of the need to estimate the read, the following methods are used depending on the circumstances.

Energy or Time of Use (TOU) estimate with at least one year of history, same customer at same premise.
TEP would generate a bill based on customer usage from the previous year using the "PREVIOUS YEAR" formula as follows:

(IF LAST YEAR'S USAGE WAS ESTIMATED, USE "PREVIOUS MONTH" METHOD DESCRIBED BELOW.)

LAST YEAR'S USAGE FOR SAME MONTH / NUMBER OF DAYS IN BILLING PERIOD = PER DAY USAGE (FOR TIME OF USE THIS WOULD BE APPLIED TO EACH PERIOD)

PER DAY USAGE X NUMBER OF DAYS IN THIS MONTH'S CYCLE = ESTIMATED USAGE (FOR TIME OF USE THIS WOULD BE APPLIED TO EACH PERIOD)

Energy or TOU estimate with at least one year of history, new customer at premise.
TEP would generate a bill using the "TREND" formula, based on customer's usage trend as described below:

TEP's Customer Information System ("CIS") would generate a bill based on trend. Customers are assigned to a Trend area which differentiate consumption based on different geographic areas. Secondly the customer is assigned to a Trend class which is used to differentiate consumption trends based on the type of service and type of property. An example of this would be residential, commercial, and industrial usage. Thirdly all consumption is identified using unit of measure code and a time of use code.

Within TEP's CIS, a trend record is created from each billed service. This record becomes part of a trend table. During estimation, consumption from three prior bill cycles is compared to the consumption from the same cycle in the previous month to determine a trend. This trend, plus a tolerance, is used to create a usage amount for bill estimation.

This customer's usage in previous period / AVERAGE CUSTOMER'S USAGE IN PREVIOUS PERIOD X Avg customer's usage in current period = estimated consumption for register read.

Energy or TOU estimate with less than one year of history, same customer at premise.
TEP would generate a bill based on customer usage from the previous month using the "PREVIOUS MONTH" formula as follows:

(IF LAST MONTH'S USAGE WAS ESTIMATED, USE "TREND" METHOD DESCRIBED ABOVE.)

LAST MONTHS USAGE / NUMBER OF DAYS IN BILLING PERIOD = PER DAY USAGE (FOR TIME OF USE THIS WOULD BE APPLIED TO EACH PERIOD)

PER DAY USAGE X NUMBER OF DAYS IN THIS MONTH'S CYCLE = ESTIMATED USAGE (FOR TIME OF USE THIS WOULD BE APPLIED TO EACH PERIOD)

Energy or TOU estimate with less than one year of history, new customer at premise.
TEP would generate a bill based on customer's usage trend as described below:

Trend method would be used. (See above.)

Energy or TOU estimate with no history.
TEP would not generate a bill until a good meter read was acquired then use known consumption to estimate previous bills.

For accounts that have a demand billing component TEP collects interval data. This interval data is used to manually estimate demands using the following methodologies:

Demand estimate with at least one year of history, same customer at same premise.
TEP would generate a bill based on customer usage from the previous year using the following formula:

LAST YEAR'S DEMAND FOR SAME MONTH = ESTIMATED DEMAND

Demand estimate with at least one year of history, new customer at same premise.
TEP would generate a bill based on customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

Demand estimate with less than one year of history, same customer at same premise.
TEP would generate a bill based on customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

Demand estimate with less than one year of history, new customer at same premise.
TEP would generate a bill based on customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

Demand estimate with no history.
TEP would not generate a bill until a good demand read was acquired then use known demand to estimate previous bills.

Exhibit D

TUCSON ELECTRIC POWER COMPANY'S

FUEL IMPLEMENTATION PLAN

1) *TEP must improve the level of documentation in all areas.*

TEP maintains records covering transactions from requests for approval to execution. All communications with the Risk Management Committee are retained to show adequate communication with Company management as well. This recommendation was implemented in 2007.

2) *TEP should prepare a policies and procedure manual for coal procurement.*

TEP has prepared a "Fuels Management Manual" and, as a subset of that Manual, a "Coal Procurement Procedure". TEP's Coal Procurement Procedure is attached to this Fuel Implementation Plan as Attachment 1.

3) *TEP should improve its measurements of risk in order to comply with Company policy regarding keeping risk at an "acceptable level".*

In order to improve its measurement of risk, TEP has improved its forecasting and analysis resources by moving from a deterministic model to a stochastic-based modeling system ("Planning and Risk"). This recommendation was implemented in January of 2008.

4) *TEP should consider revisions to its gas and power hedging policies such that hedging is performed not only to reduce price volatility but to minimize costs.*

TEP has revised its Hedging Policy to include references to 'minimizing costs' as an overall procurement objective; the TEP Hedging Policy is attached to this Fuel Implementation Plan as Attachment 2. This recommendation was approved by the TEP Risk Management Committee and implemented in December of 2008.

5) *TEP should eliminate any commercial duties from [the] designated Risk Manager.*

The TEP Risk Manager ("RM") is an employee in the Wholesale Energy department. The responsibilities of the RM, as identified in the Hedging Policy, include ensuring adherence to the hedge plan parameters, proper recording of transactions, and performance of portfolio evaluation. The TEP Risk Controller ("RC") is an employee in the Credit department. The responsibilities of the RC, or a Credit department employee under the direction of the RC, include reconciliation of internal transaction documentation with the electronic data system, gathering and validating forward price curves, and performing credit risk and market risk measurement. TEP believes the separation of the RM and the RC, both organizationally and in their respective duties, satisfies Commission Staff's expectation of having a Company employee independent of the Wholesale Energy department evaluate market risk related to fuel and purchased power. This recommendation was implemented in TEP's revised Hedging Policy, referenced above.

6) *TEP should diversify its counterparties used for financial natural gas fixed price swaps.*

TEP has made a concerted effort to expand its list of counterparties with whom it has signed International Swap Dealers Association ("ISDA") agreements. As of December 2008, TEP had ISDA agreements with 13 different counterparties. Also, TEP currently has outstanding financial gas swap transactions with 7 separate counterparties. This recommendation was implemented in the first half of 2008.

7) *TEP should create a separate legal entity for Wholesale Trading transactions.*

In Staff witness Medine's Direct Testimony she states "A separate legal entity for wholesale trading transactions will help to minimize actual or appearances of conflicts of interest and address the cross-subsidization issues. Sometimes there can be a grey area between what is best for the corporation and what is best for ratepayers". TEP agrees that avoidance of such conflicts of interest and cross-subsidization would be sound policy. However, in this case, establishing and staffing a separate legal entity is not a cost effective measure. Instead, TEP has implemented an alternative solution which adequately addresses conflict of interest and cross-subsidization issues. In the revised TEP Energy Trading Policy, effective January 2009, physical power transactions have been removed as approved trading instruments. The TEP wholesale power trading book is now comprised exclusively of financial trading instruments. Thus, physical power transactions are performed for hedging native load requirements and financial instruments are used for trading.

The Direct Testimony of Commission Staff witness Ralph C. Smith also highlights the cost/benefit challenge facing TEP if it were required to separate its trading operations into a new legal entity. In his Direct Testimony, Mr. Smith calculates that the ten percent Wholesale Trading benefit to ratepayers equates to $171,900, using 2006 test year values. The cost TEP would incur to operate a separate Wholesale Trading legal entity appears disproportionate to the customer benefit.

Attachment 1

Tucson Electric Power
A UniSource Energy Company

Subject: Coal Procurement Procedure ***No. Fuels-01***

Purpose This procedure provides guidelines for competitive bidding when procuring coal, and establishes responsibilities for the Fuels Department.

Objective The competitive bid process promotes competition and assures the right quality, quantity, service and prices for materials and contract services. These guidelines are designed to assure the integrity of the process of carrying out this objective.

Summary This directive provides the details pertaining to the following:

A. RESPONSIBILITIES

B. PROCEDURES

Responsibilities The Fuels Department is responsible for all formal communication and negotiation with suppliers and contracts in the competitive bidding process. The Fuels Department is also responsible for coordination, evaluation and recommendation and development of the final Agreement as required.

Procedures The following topics are covered in this section:

A. Quality Criteria

B. Approved Bidder List

C. Amount Required and Term of Contract

D. Request for Proposal (RFP)

E. Confidentiality of Bids

F. Review and Approval of Responses

G. Contract Award and Drafting

H. Establishment of the Purchase Order

I. Documentation and Retention

Quality Criteria - Establish Product Quality Criteria for specific Generating Station and Units. Sundt 4 can only burn coal with a maximum of one pound sulfur per million Btu. Although this does not preclude purchasing coal with a higher sulfur content and blending on-site with a lower sulfur coal to satisfy the limit, this would require purchasing additional testing and sampling equipment. That strategy is beyond the scope of this procedure.

Approved Bidder List - Coal producers that can meet the Quality Criteria and satisfy the minimum acceptable financial criteria will receive the RFP. Prospective Bidders will be asked to submit a coal analysis which will be reviewed by Sundt Power Production for potential quality concerns other than sulfur. At their discretion, a test burn could be required before the Bidder is accepted.

A bidder list is compiled consisting of vendors meeting the following criteria:

- Financial Standings
- Required Coal Quality
- Required Coal Supply Amount
- Other market constraints (deliverability, location etc.)

The list should include the vendor's name; the mine name and location; the railroad serving the mine; the marketer; and all of the appropriate contact information.

Amount Required and Term of Contract - Supply Side Planning will provide the expected consumption in Btus for a three year period. The amount of coal needed is determined by the initial inventory, the expected burn, and the Target Inventory Level Report (*Fuels-02*) as established by the Fuels Department. The term of the contract will be one, two or three years, depending on the proposals received and the expectation of the market.

Request for Proposal - The RFP will include the proposed term, quality, and quantity desired; a specific return address for responses; response dead-line and the appropriate Fuels Department contact information.

Confidentiality of Bids - Each bid response typically contains the appropriate language protecting the fuel and transportation pricing as bid. Even if the language is insufficient or non existent, the pricing information will be kept confidential. Any information provided to one vendor will also be provided to all vendors.

Review and Approval- Upon receipt of the responses the Fuels Analyst will prepare a comparative analysis and present it to the Manager of the Department. A memo will accompany the analysis with the Analyst's recommendations. The comparative analysis will include the following:

- Coal Quality (Heat Content, SO2, Ash)
- Commodity Cost
- Delivery Cost (including fuel surcharge)
- Cost per MMBtu
- Ash disposal or revenue
- Cost per KWh including any Heat Rate penalties.

Also included in the analysis will be other variables such as Take or Pay penalties; etc. and may require Production Cost modeling if necessary.

The Manager may conduct further negotiations with the participating vendors to secure the best value for the Company. The Manager makes his final recommendation based on the analysis and resulting negotiations to the Vice President of Fuels and Wholesale Marketing.

Contract Award and Drafting - Upon approval the Fuels Manager will secure a Letter Agreement. The Fuels Manager will schedule subsequent meetings with the company's Legal Counsel; the successful vendor and their legal counsel to further negotiate the final Agreement. The Agreement is signed by the appropriate representatives per TEP's signature level policies (PRES-02_-_Signature_Authorization.)

Establishment of the Purchase Order - The Fuels Analyst or the Department Assistant will submit a Purchase Requisition for the final Purchase Order.

Documentation and Retention – Steps A through H above will be documented and saved both electronically and in hard copy per corporate policy (UNS-LRC-01 - Corporate Records Management Policy.)

Attachment 2

TEP
Hedging Policy

Effective January 1, 2009

Contents

1 Introduction

1.1 Purpose

The TEP Hedging Policy addresses the procurement methodology that is to be employed to quantify risks posed to reliable service while lowering the volatility of the costs of fuels and wholesale power requirements necessary to serve TEP's customer loads.

1.2 Objectives

- Define the hedge policy including purchasing mechanisms that can be used to support TEP's hedging objectives.
- Define and monitor the line of authority, responsibility and accountability for Fuels and Wholesale Power Hedging.
- Monitor portfolio positions and provide periodic reports to Senior Management that detail positions and risk.

2 Hedge Procedure

2.1 Overview

The intent of this hedge policy is to quantify and manage risks posed to reliable service while lowering the volatility of the costs of fuels and wholesale power requirements at TEP. This volatility is attributable to risks associated with TEP's normal course of business including price risk associated with TEP's gas and purchased and sold power, volumetric risk associated with TEP load variability, and operational risk associated with TEP's power plants and transmission system.

The natural gas and power markets are susceptible to intermittent periods of high volatity. Over-reliance on spot market transactions could expose TEP to periodic extreme movements in fuel costs and power price fluctuations. This exposure, combined with the seasonality associated with TEP's gas and purchase power requirements for summer load could lead to unforeseen, detrimental swings in the costs of providing reliable service. Some short-term and spot power and gas transactions are still prudent and a portion of TEP's portfolio will continue to be managed via those markets.

Fixing forward gas and power prices as well as capacity (including transportation capacity which is pipeline capacity in the case of gas and transmission in the case of power) for TEP's summer period and maintenance outages will be the primary strategy used by TEP to stabilize costs and reduce price risks. Forward sales of TEP's excess energy in the shoulder and off peak periods will also be used to stabilize wholesale revenues to the extent possible. To execute this strategy several tools will be employed such as forecasts using forward gas and power price curves, historical load and operational data, calendar triggers and various market mechanisms.

Tools such as weather hedges, unit outage insurance, and hazard sharing agreements will also be eligible for use to mitigate volumetric and operational risk

2.2 Hedge Team

A team consisting of members from the following areas will be responsible for developing and recommending a hedging plan to the RMC. The team will be overseen by TEP's Risk Manager.

Fuels & Wholesale Power
Resource Planning
Financial Planning
Corporate Accounting
Corporate Credit
Retail Pricing/Forecasting

2.2 Hedge Strategy

2.2.1 Quantifying Fuel and Power Risk

Forecasting expected fuel and power risk involves measuring the volume of gas and purchased power historically a) seen as excess and b) required to be purchased to serve TEP's entire load (retail and wholesale). These historical amounts are combined with planned outages, growth rates, and other variables and simulations are run to generate forecasts with known confidence intervals. Existing contractual variables, such as gas-index purchased power contracts should be aggregated when quantifying fuel and power risk exposure. This risk should be analyzed based on assumed gas and wholesale power price changes and the net effect on TEP's energy risk profile. The net effect takes into account the offsetting effects of wholesale power sales for any change in gas and purchased power prices. In essence, some changes in fuel and purchased power expenses is mitigated by offsetting changes in wholesale sales gains.

Fuel and purchased/sold power expense/revenue variations result primarily from changes in gas prices as gas is the marginal fuel in the Southwest region. Market and system dynamics can however, change the mix of fuel used for generation, and these changes must be considered when determining hedging products.

2.2.2 Time Horizon

A mix of physical and financial gas and power transactions and appropriate time horizons for each will be the basis for the hedge strategy. This mix will consist of:

- Spot market transactions
- Monthly transactions (Short-term)
- Transactions for the next 12 month period (mid-term)
- Transactions farther out than one year (long-term)

TEP will analyze hedging its fuel and power risk at least three years into the future. Power purchases will be made in accordance with the ACC Competitive Procurement Report. Affiliate bids will require the use of an independent monitor.

2.2.3 Non-Discretionary & Discretionary Hedges

Non-Discretionary Purchase Hedges: At a minimum, 45% of the forecasted monthly Energy Needs (defined as April through October as gas and purchased power plus November thorugh March Luna output) Energy Needs and significant planned unit outages will be hedged with fixed prices prior to the beginning of each month. Energy Needs will be converted to equivalent gas consumption using historical heat rates for the time-periods of the power purchases. Purchased power capacity will bring the total of dispatchable resources and firm purchased power to 90% of the expected summer peak. These purchases will be mechanistic and made with the intent of reducing the amount of exposure to spot market prices during periods of high volatility. Purchased power capacity hedges will be completed no later than the end of the first quarter of each year. Non-discretionary gas purchases will be made monthly with the minimum purchase amounts met 2 months before delivery month. During the week of the 20th of each month (the "trigger date"), purchases will be made to bring the total fixed price monthly volume up to a level commensurate with 27 hedging opportunities. Power purchases will be made the same week as gas purchases, but at least 1 day prior to gas purchases to ensure the inclusion of any changes in gas-hedging amounts. Non-discretionary energy purchases will not be made in the months of August through October due to the historical volatility added by hurricanes. Capacity purchases allowed during the hurricane period.

Discretionary Hedges: Discretionary hedges are made with the intent of taking advantage of favorable purchasing opportunities and/or reducing the amount of exposure to spot market prices during periods of high volatility. Any purchase made beyond 36 months will be considered discretionary. The sum of Discretionary and Non-Discretionary purchases will not exceed 75% of the forecasted energy needs to allow room for spot purchasing and act as a buffer for lower than normal load and forecasting errors. All discretionary purchases must be approved by at least three members of the RMC.

Power Sales: Forward power sales should be planned for time periods up to 24 months to maintain a seasonal balance between wholesale sales exposure and fuel and purchased power exposure. These sales will be part of the Hedging Plan for Non-Discretionary hedges or as recommended and approved with as a Discretionary hedge.

The Trader will prepare a documentation packet for each hedge transaction (whether discretionary or non-discretionary) to memorialize the decision process for future reference.

2.2.4 Supply Locations

TEP will hedge its financial and physical gas requirements at the San Juan and/or Permian supply basin as is prudent based on capacity agreements and any dependant power agreements. Power will be hedged at locations from which TEP can reasonably expect reliable supply to/from its system. For all energy purchases and sales for which there is no available transport to the applicable location, the reason for the purchase/sale without the transport will be documented as part of the transaction.

2.3 Hedge Tools

2.3.1 TEP Forecast

TEP's integrated loads and resources forecast (Planning and Risk) will be the basis for measuring and evaluating the fuels and wholesale power risk exposure. Sensitivity to gas and power price changes as well as hedging options will be evaluated in the most current forecast. At least quarterly, updated forecasts should be integrated into the hedging plan and adjustments made to stay within the percentages discussed in section 2.2.3. In the case of unusual volatility affecting the power and/or natural gas markets, updates to TEP's forecast will be done bi-weekly.

Natural gas and power price forecasts will be based on the forward curves used in the forecast and are based on fundamental indicators such as gas storage (both current and projected), temperature forecasts, gas production (both current and projected) and historic gas trends.

2.3.2 Hedging Mechanisms

Hedging TEP's fuel and power risk may require the use of several types of hedging tools. The type of tool(s) used will depend on numerous factors including the type of risk being hedged, the availability of financial hedges, current supplier arrangements and system dynamics and constraints.

The following types of transactions will be used as the primary hedging tools:

- Fixed price forward physical gas purchases/sales at supply basins
- Fixed price forward physical power purchases
- Fixed price forward physical power sales (offsetting to purchases)
- Financial instruments (call options, collars and swaps)
- NYMEX gas purchases
- Gas basis trades to convert NYMEX to physical supply basin.

3 Hedging Plan Characteristics and Approval

3.1 Hedging Plan

Each year, in the fourth quarter, the Hedge Team will make a recommendation for the next 3 year's Hedging Plan ("Plan") to the RMC. The Plan will include an overview of the specific risks faced by TEP and a detailed explanation of the hedge strategy to be employed to mitigate those risks. The Plan will also include the timing of expected hedge transactions, calendar trigger dates, and the types of hedges that will be made if the triggers are reached.

3.2 Authorized Transactions

The Hedging Plan will be expressly approved by the RMC. Once approved, the transactions in the plan are deemed authorized for execution by the Fuels and Wholesale Power group. No other hedge transactions may be placed nor any changes made to the plan without prior approval from the RMC. If any component of the Plan cannot be carried out, the Risk Manager will notify the RMC and recommend any necessary change or correction to the Plan.

4 Transaction Responsibility Assignments

4.1 Hedge Execution

Upon approval of the Hedging Plan, the Risk Manager and Hedge Trader will insure that it is executed. A confirmation will be generated by the broker and/or counterparty and sent to the Energy Trader for filing. A trade ticket will be filled out by the trader with copies routed to the Risk Manager and Risk Controller.

Abbreviations are as follows:

T	- Trader	RM	- Risk Manager
RC	- Risk Controller	A	- Accounting/Billing

1) Transaction Activities	
a) Execute trade	T
b) Designate hedge transactions	T
c) Complete trade ticket in triplicate	T
d) Enter transaction information in WebTrader	T
e) Ensure transaction is within hedge plan parameters	T, RM
f) Memorialization/Documentation	T
2) Contract Administration	
a) Maintain customer trading and scheduling information	T
b) Maintain customer billing information	A
c) Write and route transaction agreements	T
d) Maintain copies of executed transaction agreements	T
3) Transaction Compliance	
a) Ensure proper recording of transactions	RM

b) Reconcile confirmation to trade ticket	RC
c) Reconcile transaction agreement to confirmation	T, RC
d) Reconcile confirmation to system data input	RC
e) Deliver executed transaction agreement to counterparty	T

5) Transaction Settlement

a) Reconcile invoices	A
c) Initiate payment	A
d) Ensure appropriate accounting and tax treatments	A
e) Monitor and report late payment and nonpayment	A

6) Position Control

a) Gather and input forward price curves	RC
b) Validate forward price curves	RC
c) Perform monthly portfolio evaluation	RM
d) Prepare and distribute periodic valuation reports	RM
e) Perform credit risk measurement	RC
f) Prepare and distribute periodic credit risk reports	RC
g) Perform market risk measurement	RM
h) Track GAAP and SEC compliance	RC, A
i) Monitor and report violation of authorities, limits and policies	RM, RC

4.3 Signing Authorities

Transaction agreements for authorized transactions may be signed by the Risk Manager or any member of the RMC. Other agreements may be signed by the Risk Manager or any member of the RMC necessary once approvals obtained.

4.4 Risk Policy Acknowledgement

The Risk Manager, Risk Controller and each Authorized Trader listed on Exhibit A will sign a copy of Exhibit B, "TEP Fuels and Wholesale Power Hedging Policy Acknowledgement Form". These forms must be filled out for each new revision of either Policy. The Risk Manager will maintain a record of the signed exhibits.

4.5 Ethics/Principles of Conduct and FERC Standards of Conduct

4.5.1 Ethics/Priciples

UniSource Energy Corporation (UNS) has a UNS Code of Ethics and Principles of Conduct (Code). The objective is to ensure that non-classified employees of UNS and its subsidiaries and the UNS Board of Directors are complying with the Code such that they:

1. conduct their business activities in a way that complies with the law, and
2. ensure their activities meet the highest ethical standards for business conduct.

Policy

- All unclassified employees and members of the Board of Directors will sign a questionnaire regarding compliance with the Code once a year.
- Internal Audit will summarize the completed questionnaires once a year and report thereon to the Audit Committee.
- The Corporate Compliance Officer has the responsibility to report to the Audit Committee whether any fraud as discussed in the Sarbanes/Oxley Act has been identified during the quarter.
- The Corporate Compliance Officer may request executive sessions with the Audit Committee at any time he/she believes it is appropriate.
- Internal Audit is responsible for monitoring and testing for compliance with the Code.

4.5.2 FERC Standards of Conduct

Additionally, employees are required to complete training to ensure compliance with the Federal Energy Regulatory Commission (FERC) Standards of Conduct and Anti-Market Manipulation Regulations. The Standards of Conduct provide for the independent functioning of the Wholesale Marketing Department and ensure that no undue preference is given to the Marketing Department by the transmission function.

The Anti-Market Manipulation rules are required by the Energy Policy Act of 2005.

TEP's policy requires employees to undergo training regarding both sets of regulations on an annual basis. The training will take place using an online program developed by the Edison Electric Institute.

5 Management Reporting Requirements

5.1 Overview of Management Reporting

Accurate and timely information is crucial to the control and management of risk. All Risk Management Committee members, therefore, will receive a comprehensive set of reports on a monthly basis of the business unit's risk profile and performance with monthly updates of trading positions and limits. For the months when a quarterly Risk Management Committee meeting is scheduled, the reports will be distributed prior to the meeting together with written explanation of the major movements, along with the meeting agenda.

The RMC report should be sufficient to provide adequate information to judge the changing nature of the risk profile and the business unit's performance. All RMC members will be trained on the significance and understanding of all reports.

5.2 Key Market and Credit Risk Reports

The following is a listing of selected high level reports appropriate for the Risk Management Committee related to this hedging policy.

Hedging Reports

- Current Hedges—Report of current gas and power hedges including percent of estimated monthly gas volume hedged, total volume of power hedged, hedged prices, product types and current mark-to-market of hedges.
- Stress market scenario analysis, Earnings at Risk, Value at Risk, and to the extent required by the financial environment, C-Var;
- Policy exceptions--description of exceptions with recommendations as to corrective action required;
- New transactions.

Exhibit A.

Authorized Hedge Traders
Michael Bowling
Ramondo Robey

Exhibit B.

TEP Fuels & Wholesale Power Hedging Policy Acknowledgement Form

I acknowledge that I have read TEP Fuels & Wholesale Power Hedging Policy, dated ___________________ and I agree to comply fully with the parameters outlined. I understand that willful violation of limits set within these Policies may result in disciplinary action.

________________________ ____________________

(Signature) (Date)

____

(Print Name)