Billing and Scheduling Charge: $320.00 per month.

Interruptible Power Capacity Charge: The price of the Interruptible Power Capacity is as shown in the Table 8:

TABLE 8	
Period	**Capacity Charge**
June 1, 2000 – May 31, 2001	$ 4,200/MW - Month
June 1, 2001 – May 30, 2002	$ 4,300/MW - Month
June 1, 2002 – May 31, 2003	$ 4,400/MW - Month
June 1, 2003 – May 31, 2004	$ 4,500/MW - Month

Interruptible Energy Price: The price of energy delivered to UEG shall be $2.50/MWh plus the Wholesale FCA Factor (refer to Attachment 1 and Table 5 in Option A for and estimate of the Wholesale FCA Factor).

Point of Supply: The Points of Supply shall be the generator bus or busses from any of SPS generation resources. UEG shall be responsible for reimbursing SPS for the cost of firm transmission and ancillary services through SPS from any of SPS' generation resources to the MPS transmission system, including losses, as outlined in the section entitled "Transmission and Ancillary Services."

Availability: SPS defines Availability, for any Billing Period, as the ratio expressed as a percentage of the total amount of the electrical energy SPS can continuously deliver the rated amount of contract capacity divided by the product of the Contract Capacity and the number of hours in the Billing Period. The Billing Period is hereby defined as the Hours Ending ("HE") 0100 on the first day for a given calendar month through HE 2400 on the last day of the given calendar month. In this case the, SPS guarantees an availability of 95% for Billing Periods during the Contract Period for all months June through September and an availability of 97% for Billing Periods during the Contract Period for all months October through May.

For example, in the case of Interruptible Capacity during the month of June 2000, SPS should be capable of producing up to 72,000 MWhs (100 MW x 720 hours) during the Billing Period. Therefore, SPS will fail to meet its 95% availability criteria if SPS is unable to deliver more than 3,600 MWhs (0.05 x 72,000 MWhs) to UEG, if and only if UEG has scheduled such energy for delivery from SPS during Billing Period during June 2000.

Energy Scheduling: The energy shall be scheduled by notifying SPS by 8:30am for all energy to be delivered for the following day unless mutually agreed upon otherwise by both parties. Should UEG need to schedule Interruptible Energy on an emergency basis (i.e. only two hours notice), SPS can quote to UEG the price of electric energy for delivery. The minimum amount of energy to be scheduled shall 10 MW for one hour. There are no monthly or annual minimum energy take requirements. SPS reserves the right to supply the energy from other SPS generation resources, or other sources that can make that energy available for delivery to MPS through any available interconnection with MPS.

Buy-Out Provision: Should UEG wish to remove itself from its Interruptible Power capacity purchase obligations for the Contract Years beginning June 1, 2002 through May 31, 2004, UEG may do so under the schedule shown in Table 9:

TABLE 9			
Contract Year	**Notice of Buy -Out Given During:**	**Amount of Capacity to Buy-Out**	**Cost per MW of Capacity Buy-Out**
June 2002 through May 2003	10/1/2001 - 12/31/2001	Up to 150 MW	$880/MW – Month
June 2002 through May 2003	1/1/2002 - 2/28/2002	Up to 150 MW	$1,760/MW – Month
June 2003 through May 2004	10/1/2002 - 12/31/2002	Up to 150 MW	$900/MW – Month
June 2003 through May 2004	1/1/2003 - 2/28/2003	Up to 150 MW	$1,800/MW – Month

Other General Buy-Out Provisions:

- UEG may buy-out all, or portions thereof, of their capacity obligations in 50 MW increments, during the Contract Years for June 2002 - May 2003 and June 2003 - May 2004, provided that in any remaining blocks of capacity UEG continues to purchase during the months of October through May, are purchased in amounts no less than what will be purchased for June through September of the same Contract Year.

After February 28, 2002, UEG cannot remove itself from the obligation to purchase the capacity for June 2002 - May 2003, but will still have the ability to buy-out of its obligation to purchase capacity for the Contract Year June 2003 - May 2004, for the amount shown in Table 9.

- UEG shall reimburse SPS for long-term transmission and ancillary services purchased to meet delivery obligations to MPS.
- SPS shall not be liable for any 'stranded costs' of UEG relating to fuel acquisitions or fuel transportation arrangements should UEG execute any buy-out provision.

TRANSMISSION AND ANCILLARY SERVICES

As per Section C and G of the UEG's request for proposals, SPS will provide for transmission and ancillary services from the Point of Supply to the Point of Delivery under separate agreements, under which UEG shall reimburse SPS the total costs incurred for these services. The actual cost for these services will be those in affect at the time this transaction is initiated, and as it may be adjusted by the providers throughout the term of this transaction. To help UEG in the evaluation of this proposal, the costs from the various transmission and ancillary service providers and the SPP Regional Transmission Tariff as shown in Attachment 2. SPS will work closely with UEG to ensure the most reliable and economical transmission and ancillary services are acquired for this agreement.

UEG may request SPS deliver energy, under terms of this agreement, to UtiliCorp's West Plains Energy – Kansas Division (WPEKS), subject to the availability of SPS' transmission and regulatory conditions that may impact both MPS and WPEKS. SPS would also like to point out that flows from SPS to MPS, scheduled through WPEKS, will have the net affect of displacing generation and energy from the Jeffrey Energy Center in Central Kansas, of which MPS currently derives a portion of its total capacity resources.

The cost of the energy from the options listed above does not take into account the effect of the losses incurred when transmitting electrical energy across various transmission systems. UEG, at its choosing, can either 1) take receipt of the energy at the Point of Delivery minus an amount of energy equal to the losses incurred to delivery the energy, 2) purchase the losses, through SPS, from either the SPP or other regional transmission providers, or 3) purchase the losses directly from the SPP or other regional transmission providers.

SPS understands that these terms and conditions are subject to review and approval by UEG as stated in the request for proposal. This proposal is valid through August 31, 1998 and is subject to prior sale and the completion of a definitive agreement, management approvals, and the availability of transmission and ancillary services from SPS, the Southwest Power Pool, and any other transmission provider from which transmission services are necessary in order to deliver firm capacity and energy to UEG.

If you have any questions, comments or need additional information, please feel free to call me at 806-378-2376.

Sincerely,

Mike Martin
Regional Power Sales Representative

cc: Todd Hegwer

Southwestern *PUBLIC SERVICE* Company

COMMISSION	SCHEDULE	SHEET	RATE SCHEDULE NUMBER	
~~FERC~~				

WHOLESALE FUEL COST ADJUSTMENT CLAUSE

TARIFF NUMBER	~~7105.1~~
CANCELLING	~~7105.0~~

1. The charges for actual wholesale service rendered during the current billing period shall be increased or decreased by an adjustment amount, per kilowatt-hour of sales (to the nearest 0.0001¢), equal to the difference between the estimated fuel cost (eF) per kilowatt-hour of estimated sales (eS) in the current, or billing, period (m) and the base period (b), as adjusted to allow for wholesale losses (L), with the total charges adjusted by a dollar amount to correct for prior wholesale over or under collections:

$$\text{Adjustment Factor} = \left[\frac{eFm}{eSm} - \frac{eFb}{eSb}\right] (L)$$

2. Fuel costs (F) shall be the cost of:

(i) Fossil and nuclear fuel consumed in the Company's own plants, and the Company's share of fossil and nuclear fuel consumed in jointly owned or leased plants.

(ii) Plus, the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (iii) below. Included therein shall be the portion of the cost of purchases from Qualifying Facilities at or below Company's avoided variable energy cost.

(iii) Plus, the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such charges), when such energy is purchased on an economic dispatch basis. Included therein may be such costs as:

(1) charges incurred for economy energy purchases and

(2) charges incurred as a result of scheduled outages,

all such kinds of energy being purchased by the Company to substitute for its own higher cost energy.

Effective Date January 1, 1990 Approved [signature]

TAR62

(iv) Less, the cost of fossil and nuclear fuel recovered through inter-system sales, including the fuel costs recovered from economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be equated to:

(i) the sum, measured at the bus-bar or interconnection point, of (1) generation, (2) purchases, and (3) interchange-in,

(ii) less (1) inter-system sales, as referred to in 2.(iv) above, and (2) inter-system losses.

4. "L", the adjustment for wholesale losses, determined at the wholesale delivery points, shall be equal to:

$$1.039 = \frac{1}{1 - 3.754\%}$$

5. The current month adjustment for prior wholesale over or under collections shall be calculated as:

(i) the first prior month's (p) actual fuel costs (aF) divided by actual sales (aS),

(ii) minus that month's (p) estimated fuel costs (eF) divided by estimated sales (eS),

(iii) times the wholesale loss adjustment (L),

(iv) times actual wholesale sales (W) in that month (p) for each customer.

$$\text{Adjustment Amount} = \left[\frac{aFp}{aSp} - \frac{eFp}{eSp}\right] (L)\ (Wp)$$

The adjustment amount shall be debited or credited to the current month's billing.

6. (i) The fuel cost adjustment factor calculation shall not include:

(1) the net energy cost of electric energy purchased from Celanese Corporation and,

(2) the kilowatthours generated at the Celanese Corporation chemical plant, not to exceed the amount of electric energy consumed at that plant.

(ii) The fuel cost adjustment factor calculation shall include both the net energy cost of energy purchased from Celanese, and the kWh generated at its plant, for any amount of energy which does exceed the amount consumed at that plant.

ATTACHMENT 2

Transmission and Ancillary Service Charges: The following table outlines the various charges to deliver the capacity and energy to MPS:

Southwestern Public Service	Demand Charge	Energy Charge
Firm Transmission	$1,358/MW - month	
Scheduling	$28.9/MW - month	
VAR/Voltage Support	$34.6/MW - month	
Losses	See Note 1.	
West Plains Energy – KS (WPEKS)		
Firm Transmission	$1,083/MW - month	
Scheduling	$54.0/MW - month	
VAR/Voltage Support		$0.190/MWh
Losses	See Note 2.	
Western Resources (WRI)		
Firm Transmission	$1,300/MW - month	
Scheduling		$0.1561/MWh
VAR/Voltage Support	$39.47/MW - month	
Losses	See Note 3.	
Central and Southwest (CSW)		
Firm Transmission	$1,100/MW - month	
Scheduling	See Note 4.	
VAR/Voltage Support	See Note 5.	
Losses	See Note 6.	

Note 1: Losses for SPS system are as follows:
Demand Related Loss Factor is 3.6984%
Energy Related Loss Factor is 4.4863%

Note 2: Losses for WPEKS are 6.0% in the months May - October, 5.0% in the months November - April.

Note 3: Losses will be as follows (from WRI's OA Tariff):

Real Power Losses shall be calculated by multiplying the capacity and energy received at the Receipt Points by the applicable Real Power Loss factors stated below for the voltage at the Point of Receipt or Point of Delivery, whichever is lower. For deliveries to a Control Area interface, the Real Power Loss factor shall be the average of the applicable factors stated below for each interconnection within the interface.

Voltage	Meter Location	Transmission Losses
230-345 KV	High Side	0.87%
	Low Side	1.62%
115-161 KV	High Side	1.62%
	Low Side	3.04%
34.5-69 KV	High Side	3.04%
	Low Side	4.43%

Where:

"High Side" refers to a line tap meter location at the stated voltage or, in the case of a delivery point requiring the use of a step-down transformer, to the high voltage side of such transformer.

"Low Side" refers to a meter within a substation and located on the low voltage side of a step-down transformer.

"Bus" refers to a meter within a substation and located on the substation bus at the stated voltage.

"Circuit" refers to a line tap meter location at the stated voltage.

Note 4: CSW charges $66/transaction/day for each schedule across CSW's transmission system within the SPP.

Note 5: As per CSW's OA Tariff, "Reactive Supply and Voltage Control from Generation Sources Service will be provided directly by PSO/SWEPCO as the Control Area operator. The Transmission Customer must purchase this service from PSO/SWEPCO. PSO/SWEPCO will not impose a separate charge for Reactive Supply and Voltage Control from Generation Sources Service."

Note 6: The Loss Factors on the CSW's alternating current facilities in the SPP are as follows:

Capacity loss factor: 3.3%
Capacity loss factor: 1.7%

The Transmission and Ancillary Service Charges are based on the SPS', WRI's, CSW's and WPEKS' open access tariffs. The actual cost for these services will be those in affect at the time this transaction is initiated, and as it may be adjusted by the providers throughout the term of this transaction.

Based on the firm transmission charges from SPS' generating resources, the most cost effective path to MPS is from SPS through WPEKS and WRI, although an alternate path from SPS through CSW and WRI is available. Actual paths and charges will depend upon the various Available Transmission Capacity (ATC) between the above transmission providers at the time transmission is requested and/or obtained.

ATTACHMENT 2

SPS - MPS
FIRM

MW-Mile($)					
Hourly Off-Peak	Hourly On-Peak	Daily	Weekly	Monthly	Last Updated
4.107	8.648	138.374	691.872	2998.11	05/17/1998

Schedule Fee($)				
Hourly	Daily	Weekly	Monthly	Last Updated
0.09	1.399	7.025	30.003	05/19/1998

Reactive Voltage($)				
Hourly	Daily	Weekly	Monthly	Last Updated
0.034	0.982	5.627	24.09	05/19/1998

Loss Percentage		
On-Peak	Off-Peak	Last Updated
-4.6%	-1.59%	05/31/1998

Back to Price Matrix
Back to OASIS

Prices based on 1 MW

*The Southwest Power Pool administration fee is $0.15 per MWH.
**The rates provided are an approximation for transmission service charges for SWPP. This estimate is based on the most recent transmission ownership, power flow, and date submitted for MW-Mile calculation and the charges set forth by SWPP.
***The rates provided are not to be constructed as a quote. actual charges may vary depending upon the data available at billing time.

The prices shown above are from the SPP Price Matrix for the summer months June through September.

NEW CENTURY
ENERGIES™

PUBLIC SERVICE
COMPANY OF COLORADO™

SOUTHWESTERN
PUBLIC SERVICE COMPANY™

CHEYENNE LIGHT
FUEL & POWER™

PO Box 1261
Amarillo Texas 79170-0001
Telephone 806.378.2121

August 21, 1998

UtiliCorp Energy Group
Attn: Mr. Frank A. Debacker
107500 East 350 Highway
Kansas City, Missouri 64138

RE: Proposal Clarification, SPS bid dated July 3, 1998 for capacity and energy to Missouri Public Service Company ("MPS").

Dear Frank,

In response to your questions concerning the reserves associated with the firm power option, SPS has the following response.

For the firm power associated with "Option A – Partial Requirement Power Service, with Peaking Power Service," SPS will carry the pool planning reserves, in accordance with the current rules and procedures of the Southwest Power Pool ("SPP"), which is currently 12%. Therefore, if MPS purchased 100MW of firm capacity under the terms of Option A, SPS will carry an additional 12 MW in planning reserves.

This definition of reserves and firm capacity apply to the attached revised bid. If you have any questions, please feel free to call me at 806-378-2376.

Sincerely,

Mike Martin

Mike Martin
Regional Power Sales Representative

mm
cc: Todd Hegwer

NEW CENTURY ENERGIES™

PUBLIC SERVICE COMPANY OF COLORADO®
SOUTHWESTERN PUBLIC SERVICE COMPANY®
CHEYENNE LIGHT FUEL & POWER®

PO Box 1261
Amarillo, Texas 79170-0001
Telephone 806.378.2121

August 21, 1998

UtiliCorp Energy Group
Attn: Mr. Frank A. Debacker
107500 East 350 Highway
Kansas City, Missouri 64138

RE: Purchase of Resource Specific Capacity and Energy for the period June 1, 2000, through May 31, 2001.

In response to UtiliCorp Energy Group's ("UEG") request for proposals, Southwestern Public Service Company ("SPS") will agree to sell the following resource specific capacity and energy to UEG's operating division Missouri Public Service ("MPS") under the terms presented herein, pursuant to and in accordance with SPS' Market Based Tariff. Terms used, but not defined herein shall have the meaning ascribed to them in the definitive agreement. Information contained in this response is to be used solely by UEG for evaluation purposes only and contains privileged and confidential information not to be shared with third parties without prior written consent of SPS. This offer for resource specific capacity and energy cancels and supercedes SPS' offer to MPS dated July 3, 1998.

PARTIAL REQUIRMENT POWER SERVICE

The term "Partial Requirements Power Service" shall mean that quantity of firm electric power and associated energy that SPS will make continuously available to UEG and which will meet the capacity and energy needs of UEG.

Contract Period: The months of June 1, 2000 through May 31, 2001.

Partial Requirements Capacity Amounts: As per the following Table 1:

TABLE 1	
Period	**Capacity**
June 1, 2000 - May 31, 2001	50 MW, up to 100 MW, in whole MW increments

Partial Requirements Capacity Charge: The price of the Partial Requirements Power Service Capacity is as shown in the Table 2:

TABLE 2	
Period	**Capacity**
June 1, 2000 - May 31, 2001	$ 5,200/MW - Month

Partial Requirements Energy Price: The price of energy delivered to UEG shall be $0.80/MWh plus the Wholesale Fuel Cost Adjustment Factor.

Wholesale Fuel Cost Adjustment Factor: Attachment 1 is a copy of SPS' Wholesale Fuel Cost Adjustment (FCA) Clause currently in effect. Table 3 shows an <u>estimate</u> of the anticipated Wholesale FCA for the months shown.

TABLE 3	
Year	**Projected Wholesale FCA Factor ($/MWh)**
June, 2000	19.74
July, 2000	19.89
August, 2000	19.84
September, 2000	19.49
October, 2000	19.95
November, 2000	20.92
December, 2000	20.48
January, 2001	20.77
February, 2001	20.09
March, 2001	19.46
April, 2001	19.41
May, 2001	19.55

Unless another method is mutually agreed upon, SPS will notify UEG of the estimated Wholesale FCA Factor prior to the upcoming month. Any deviations from the actual to the estimated Wholesale FCA Factor shall be accounted for in the month immediately following.

Point of Supply: The Points of Supply shall be the generator bus, or busses, from any of SPS generation resources. UEG shall be responsible for reimbursing SPS for the cost of firm transmission and ancillary services through SPS from any of SPS' generation resources to the MPS transmission system, including losses, as outlined in the section entitled "Transmission and Ancillary Services."

Availability: In the case of Partial Requirements Power Service, with Peaking Power Service, SPS defines availability as the amount of available capacity from SPS generation resources designated to deliver energy to its firm customers. As long as SPS has generation available to its firm customers, SPS will supply the energy.

Partial Requirements Energy Scheduling: The energy shall be scheduled by notifying SPS by 8:30am Central Prevailing Time for all energy to be delivered for the following day unless mutually agreed upon otherwise by both parties. Should UEG need to schedule Partial Requirements Energy on an emergency basis (i.e. only two hours notice), SPS can quote to UEG the price of electric energy for delivery. The minimum amount of energy to be scheduled shall be 10 MW for one hour. There are no monthly or annual minimum energy take requirements. SPS reserves the right to supply the energy from other SPS generation resources, or other sources that can make that energy available for delivery to MPS through any available interconnection with MPS.

TRANSMISSION AND ANCILLARY SERVICES

As per Section C and G of the UEG's request for proposals, SPS will provide for transmission and ancillary services from the Point of Supply to the Point of Delivery under separate agreements, under which UEG shall reimburse SPS the total costs incurred for these services. The actual cost for these services will be those in affect at the time this transaction is initiated, and as it may be adjusted by the providers throughout the term of this transaction. To help UEG in the evaluation of this proposal, the costs from the transmission and ancillary service providers are shown in Attachment 2. SPS will work closely with UEG to ensure the most reliable and economical transmission and ancillary services are acquired for this agreement.

UEG may request SPS deliver energy, under terms of this agreement, to UtiliCorp's West Plains Energy – Kansas Division (WPEKS), subject to the availability of SPS' transmission and regulatory conditions that may impact both MPS and WPEKS. SPS would also like to point out that flows from SPS to MPS, scheduled through WPEKS, will have the net affect of displacing generation and energy from the Jeffrey Energy Center in Central Kansas, of which MPS currently derives a portion of its total capacity resources.

The cost of the energy from the options listed above does not take into account the effect of the losses incurred when transmitting electrical energy across various transmission systems. UEG, at its choosing, can either 1) take receipt of the energy at the Point of Delivery minus an amount of energy equal to the losses incurred to deliver the energy, 2) purchase the losses, through SPS, from the regional transmission providers, or 3) purchase the losses directly from the regional transmission providers.

SPS understands that these terms and conditions are subject to review and approval by UEG as stated in the request for proposal. This proposal is valid through September 30, 1998 and is subject to prior sale and the completion of a definitive agreement, management approvals, and the availability of transmission and ancillary services from SPS and any other transmission provider from which transmission services are necessary to deliver firm capacity and energy to UEG.

If you have any questions, comments, or need additional information, please feel free to call me at 806-378-2376.

Sincerely,

M to Martin

Mike Martin
Regional Power Sales Representative

cc: Todd Hegwer

ATTACHMENT 1

Southwestern *PUBLIC SERVICE* Company

COMMISSION	SCHEDULE	SHEET	RATE SCHEDULE NUMBER
~~FERC~~			

WHOLESALE FUEL COST ADJUSTMENT CLAUSE

TARIFF NUMBER	~~7105.1~~
CANCELLING	~~7105.0~~

1. The charges for actual wholesale service rendered during the current billing period shall be increased or decreased by an adjustment amount, per kilowatt-hour of sales (to the nearest 0.0001¢), equal to the difference between the estimated fuel cost (eF) per kilowatt-hour of estimated sales (eS) in the current, or billing, period (m) and the base period (b), as adjusted to allow for wholesale losses (L), with the total charges adjusted by a dollar amount to correct for prior wholesale over or under collections:

$$\text{Adjustment Factor} = \left[\frac{eFm}{eSm} - \frac{eFb}{eSb}\right] (L)$$

2. Fuel costs (F) shall be the cost of:

   (i) Fossil and nuclear fuel consumed in the Company's own plants, and the Company's share of fossil and nuclear fuel consumed in jointly owned or leased plants.

   (ii) Plus, the actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (iii) below. Included therein shall be the portion of the cost of purchases from Qualifying Facilities at or below Company's avoided variable energy cost.

   (iii) Plus, the net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such charges), when such energy is purchased on an economic dispatch basis. Included therein may be such costs as:

   (1) charges incurred for economy energy purchases and

   (2) charges incurred as a result of scheduled outages,

   all such kinds of energy being purchased by the Company to substitute for its own higher cost energy.

Effective Date January 1, 1990 Approved Bill D. White

TAR62

(iv) Less, the cost of fossil and nuclear fuel recovered through inter-system sales, including the fuel costs recovered from economy energy sales and other energy sold on an economic dispatch basis.

3. Sales (S) shall be equated to:

(i) the sum, measured at the bus-bar or interconnection point, of (1) generation, (2) purchases, and (3) interchange-in,

(ii) less (1) inter-system sales, as referred to in 2.(iv) above, and (2) inter-system losses.

4. "L", the adjustment for wholesale losses, determined at the wholesale delivery points, shall be equal to:

$$1.039 = \frac{1}{1 - 3.754\%}$$

5. The current month adjustment for prior wholesale over or under collections shall be calculated as:

(i) the first prior month's (p) actual fuel costs (aF) divided by actual sales (aS),

(ii) minus that month's (p) estimated fuel costs (eF) divided by estimated sales (eS),

(iii) times the wholesale loss adjustment (L),

(iv) times actual wholesale sales (W) in that month (p) for each customer.

$$\text{Adjustment Amount} = \left[\frac{aFp}{aSp} - \frac{eFp}{eSp}\right] (L)\ (Wp)$$

The adjustment amount shall be debited or credited to the current month's billing.

6. (i) The fuel cost adjustment factor calculation shall not include:

(1) the net energy cost of electric energy purchased from Celanese Corporation and,

(2) the kilowatthours generated at the Celanese Corporation chemical plant, not to exceed the amount of electric energy consumed at that plant.

(ii) The fuel cost adjustment factor calculation shall include both the net energy cost of energy purchased from Celanese, and the kWh generated at its plant, for any amount of energy which does exceed the amount consumed at that plant.

UtiliCorp MPS Proposal
August 21, 1998

ATTACHMENT 2

Transmission and Ancillary Service Charges: The following table outlines the various charges to deliver the capacity and energy to MPS:

Southwestern Public Service	**Demand Charge**	**Energy Charge**
Firm Transmission	$1,358/MW - month	
Scheduling	$28.9/MW - month	
VAR/Voltage Support	$34.6/MW - month	
Losses	See Note 1.	
West Plains Energy – KS (WPEKS)		
Firm Transmission	$1,083/MW - month	
Scheduling	$54.0/MW - month	
VAR/Voltage Support		$0.190/MWh
Losses	See Note 2.	
Western Resources, Inc. (WRI)		
Firm Transmission	$1,300/MW - month	
Scheduling		$0.1561/MWh
VAR/Voltage Support	$39.47/MW - month	
Losses	See Note 3.	
Central and Southwest (CSW)		
Firm Transmission	$1,100/MW - month	
Scheduling	See Note 4.	
VAR/Voltage Support	See Note 5.	
Losses	See Note 6.	

Note 1: Losses for SPS system are as follows:
Demand Related Loss Factor is 3.6984%
Energy Related Loss Factor is 4.4863%

Note 2: Losses for WPEKS are 6.0% in the months May - October, 5.0% in the months November - April.

Note 3: Losses will be as follows (from WRI's OA Tariff):

Real Power Losses shall be calculated by multiplying the capacity and energy received at the Receipt Points by the applicable Real Power Loss factors stated below for the voltage at the Point of Receipt or Point of Delivery, whichever is lower. For deliveries to a Control Area interface, the Real Power Loss factor shall be the average of the applicable factors stated below for each interconnection within the interface.

Voltage	Meter Location	Transmission Losses
230-345 KV	High Side	0.87%
	Low Side	1.62%
115-161 KV	High Side	1.62%
	Low Side	3.04%
34.5-69 KV	High Side	3.04%
	Low Side	4.43%

Where:

"High Side" refers to a line tap meter location at the stated voltage or, in the case of a delivery point requiring the use of a step-down transformer, to the high voltage side of such transformer.

"Low Side" refers to a meter within a substation and located on the low voltage side of a step-down transformer.

"Bus" refers to a meter within a substation and located on the substation bus at the stated voltage.

"Circuit" refers to a line tap meter location at the stated voltage.

Note 4: CSW charges $66/transaction/day for each schedule across CSW's transmission system within the SPP.

Note 5: As per CSW's OA Tariff, "Reactive Supply and Voltage Control from Generation Sources Service will be provided directly by PSO/SWEPCO as the Control Area operator. The Transmission Customer must purchase this service from PSO/SWEPCO. PSO/SWEPCO will not impose a separate charge for Reactive Supply and Voltage Control from Generation Sources Service."

Note 6: The Loss Factors on the CSW's alternating current facilities in the SPP are as follows:

Energy loss factor: 2.0%

The Transmission and Ancillary Service Charges are based on the SPS', WRI's, CSW's and WPEKS' open access tariffs. The actual cost for these services will be those in affect at the time this transaction is initiated, and as it may be adjusted by the providers throughout the term of this transaction.

Based on the firm transmission charges from SPS' generating resources, the most cost effective path to MPS is from SPS through WPEKS and WRI, although an alternate path from SPS through CSW and WRI is available. Actual paths and charges will depend upon the various Available Transmission Capacity (ATC) between the above transmission providers at the time transmission is requested and/or obtained.

NorAm/Houston Industries

NORAM ENERGY SERVICES

POWER MARKETING DEPARTMENT

1111 LOUISIANA STREET, 8th FLOOR
HOUSTON, TX 77002

P.O. BOX 4455
HOUSTON, TX 77210-4455

MEMO

DATE: 7.2.98

TO: Kiah Harris

CO.: Burns & McDonnell

FROM: TDLane Terry D. Lane (P) 713.207.5117 (F) 713.207.9626
(E-mail) tdlane@noram.com

RE: Utilicorp RFP dated 5.22.98 for Capacity and Energy for MPS

Houston Industries is interested in discussing its plans for owning and operating generation in the Midwest with Utilicorp. We are responding to the RFP with an indicative proposal at this time. We will soon announce the construction of a large generating station in an area that could provide Capacity and Energy to Utilicorp for MPS. We would welcome the opportunity to meet with you and Utilicorp after that announcement to see how we can arrive at a mutually beneficial relationship. Please contact me after you discuss this possibility with Utilicorp.

PROPOSAL

CONFIDENTIAL

NorAm Energy Services (NES) offers the following indicative proposal to Utilicorp Energy Group for delivery of Capacity and Energy to Missouri Public Service Company (MPS) as a result of the Resource Specific Capacity and Energy RFP issued May 22, 1998. Houston Industries (HI), the parent company of NES, anticipates the announcement a merchant plant to be constructed in the Midwest in the near future. Construction of that plant will allow NES to name a specific source for Capacity and Energy as required by the RFP.

Capacity Pricing:

Contract Period	Annual Capacity	\$/MW-mo
6/1/2001 to 5/31/2002	100MWs	8500
6/1/2002 to 5/31/2003	100MWs	8750
6/1/2003 to 5/31/2004	100MWs	9000

Energy Pricing:

Contract Period	Annual Load Factor	\$/MWh
6/1/2001 to 5/31/2002	100%	22.00
6/1/2002 to 5/31/2003	100%	22.50
6/1/2003 to 5/31/2004	100%	23.00

The Point of Delivery shall be at an interconnection point of the MPS transmission system.

NES shall arrange for firm transmission from its source to the Point of Delivery. The transmission price shall be passed through to MPS at cost and with no profit to NES.

For purposes of this indicative proposal, NES is not interested in discussing buyout options or guaranteed availability. NES and Houston Industries Power Generation (HIPG) are definitely interested in discussing our plans for generation assets in the Midwest and Utilicorp's future needs for Capacity and Energy. We would appreciate the opportunity to discuss these issues outside the RFP process. We will keep you informed of our progress on this particular generation project. The possibility exists that we could offer more Capacity and Energy from this plant or others that might be constructed.

NORAM

ENERGY SERVICES

POWER MARKETING DEPARTMENT

1111 LOUISIANA STREET, 8th FLOOR
HOUSTON, TX 77002

P.O. BOX 4455
HOUSTON, TX 77210-4455

MEMO

DATE: 9/4/98

TO: Frank DeBacker

CO.: UtiliCorp

FROM: Terry D. Lane (P) 713.207.5117 (F) 713.207.9626
(E-mail) tdlane@noram.com

Thanks for your letter dated 8/25/98 regarding the Power Supply RFP for MPS. Houston Industries is definitely interested in being a part of the RFP process. At this time, we will leave in place the proposal we originally submitted. We may be interested in supplying more than 100 MWs. As I mentioned in follow-up correspondence, we are anticipating supplying from a facility to be constructed in Wood River, IL. We are also interested in discussing the possibility of building in MPS territory to serve the entire RFP requirement. Houston Industries has committed to building or acquiring generation assets in strategic locations. Supplying the MWs needed in this RFP fits well in that strategy.

We are hopeful that we will make whatever short list you arrive at and that we can begin detailed discussions soon. And thanks again for the opportunity to respond. I'll look forward to hearing from you.

NorAm Energy Services, Inc.

A Subsidiary of Houston Industries Incorporated

December 1, 1998

Frank A. DeBacker
Utilicorp United
P.O. Box 11739
Kansas City, MO 64138

Dear Mr. DeBacker:

As a result of our meeting at your office on November 9, 1998, Houston Industries is submitting the attached Long-Term Peaking Capacity and Energy Proposal for discussion purposes. We look forward to discussing it in detail with you in the near future.
If you have questions or comments, please call me at 713.207.5117.

Sincerely,

Terry D. Lane

Terry D. Lane
Marketing Director, MAPP/SPP

P.O. Box 4455 • Houston, TX 77210-4455 • 713 / 207-5072 • FAX 713 / 207-9626

LONG-TERM PEAKING CAPACITY AND ENERGY PROPOSAL

Buyer:	UtiliCorp United d.b.a Missouri Public Service Company (MPS)
Seller:	Houston Industries Power Generation and NorAm Energy Services (HIPG/NES)
Term:	Five years starting June 1, 2001 and ending May 31, 2006
Capacity:	300 MWs at 99 degrees F; 326 MW at 55 degrees F (yearly average)
Delivery Point:	MPS Pleasant Hill Substation
Capacity Price:	$4.50/kW-mo (escalated at 2.5% per contract year) paid on the average annual Capacity of 326 MWs; includes 16" lateral pipeline cost.
Energy Price:	For all hours, MPS will have the option to call on the Energy at $1.00/MWh (escalated at 2.5% per contract year) plus the product of a 10,600 Btu/kWh heat rate and the natural gas fuel cost.
Flexibility:	MPS has full dispatch rights to 300 MWs limited only by the scheduling provisions below and the operational constraints of the unit (such as, but not limited to, a 4 hour minimum run time).
Fuel:	Natural gas supply and transportation will be managed by Seller. Seller will supply fuel at a mutually acceptable index, adjusted for delivery to the generating facility, along with a fixed charge for six Summer months of Firm Transportation. Seller will maintain Firm Transportation for natural gas for the generating facility in the November through April period.
Unit Starts:	MPS will not be charged for the first 50 starts per contract year. MPS will be charged $2,500 per start for the second 50 starts per contract year. However, should MPS request more than 100 starts per contract year, MPS will be subject to paying incremental increases in maintenance and operating costs.
Scheduling:	MPS will notify Seller of total planned output and number of starts by 9:00 AM Central Prevailing Time (CPT) one business day prior to flow so that fuel can be procured and transported.
	If MPS provides a schedule after the 9:00 AM deadline, the gas price component of the Energy Price will be based on actual purchase cost and actual production from the unit will be conditioned on fuel availability.

Availability: The development plan envisions using proven technology which has historically attained very high availability levels. Availability targets will be set following further development effort. Seller envisions targets of 98% for all hours during the six Summer months. To provide appropriate operational incentives, the capacity payment will be adjusted (up or down) based upon actual performance relative to a specific target during the six Summer months of May through October.

Operations: HIPG will be responsible for managing operations and maintenance in accordance with generally accepted utility practices. MPS and Seller will cooperate to set scheduled maintenance outages. MPS will provide an on-site operations staff to Seller under a separate agreement.

Transmission: MPS will cooperate with Seller to accelerate the planned connection of the Pleasant Hill Substation to the 345 kv system.

Site: Under separate agreement, Seller will acquire approximately 70 acres of land near the Pleasant Hill Substation from MPS for approximately $3000 per acre.

Resale: In periods where MPS has not scheduled the Energy, Seller will have the right to sell the Energy.

Credit Support: The Seller's contract obligations are backed by a multi-billion dollar corporation with an investment grade rating. MPS's contract obligations are backed by ___________.

Note: If MPS provides fuel to the facility under a tolling arrangement, Seller will require access to Incremental Firm Transportation of natural gas for:

(a) Any Energy sales above the 326 MWs contracted for by MPS

(b) Energy sales by Seller when MPS does not call on its Energy

(c) Energy sales from this facility after the termination of this five-year agreement, if it is not renewed by both parties.

This document is not intended to create a binding offer or contract of purchase and sale of electric power or natural gas between MPS and Seller. Moreover, this document does not in any way whatsoever obligate either of the parties to enter into any agreements or to proceed with any possible relationship or transaction. The terms and conditions set forth above are subject to negotiation, completion and incorporation into and the execution by both parties of a definitive agreement. Either party may terminate discussions and/or negotiations regarding this document at any time.

HI Wholesale Energy Group
A Division of Houston Industries Incorporated

Proposal to:

Missouri Public Service Co.

January 6, 1999

Assumptions - OCGT

- 500MW OCGT facility built on MPSC site
  - 10,600 net unit heat rate
  - Availability guarantee of 98% in summer
- Capacity available year round - 500 MW
- Day ahead scheduling
- Strike at Spot Natural Gas Price x Heat Rate
- Energy from lowest cost source
  - Market
  - Peaker

Analysis methodology

- Simulate hour by hour forward market
- Simulate MPS plant dispatch and wholesale market activity
  - –Plant analysis - forced and scheduled outages
  - –Market analysis - Optimization of plants vs. market power
- Simulate OCGT capacity and match to MPS demand shape
  - – Only run OCGT when economical relative to prevailing market
  - – Determine "credit" for merchant capacity
- Determine overall cost to serve demand with OCGT configuration

Analysis Methodology - continued

- Simulate CCGT capacity and match to MPS demand shape and proposed seasonal capacity arrangement

  – Only run CCGT when economical relative to prevailing market

  –Determine "credit" for merchant capacity

- Major CCGT Assumptions
  - Heat Rate at 6200 Btu/kWh
  - Capacity Charge $7.50/kW-Mo.
  - $2.00/MWh Variable O&M (start-up, chemicals, water, etc.)

- Determine overall cost to serve demand with CCGT configuration

- Revise HI's initial OCGT offering to match CCGT economics

Results of Analysis

- HIPG's initial proposal was 5% higher than CCGT proposal
  - Not an "apple to apple" comparison due to varying risk profiles
- Significant portion of the value in CCGT proposal is from the resale of excess energy to the market
  - Higher merchant risk to MPS vs OCGT proposal
  - Significantly more risk to MPS in bear market than OCGT proposal
- Actual demand curves show that 500 MW of capacity needed in four summer months not six months
  - CCGT offering needs the two additional months to make economics work
- Revised OCGT proposal makes apparent cost equal to CCGT
  - Reduced merchant risk
  - Market upside potential with limited down-side risk
  - Matches load profile more efficiently

Regulatory capacity

- 200 MW of winter and shoulder capacity fully NERC creditable in SPP
- 500 MW of "Summer Peaking" capacity fully NERC creditable in SPP (meets 4-month criteria)

Rcvd: 1/6/99 1100

LONG-TERM PEAKING CAPACITY AND ENERGY PROPOSAL

Buyer:	UtiliCorp United d.b.a Missouri Public Service Company (MPS)
Seller:	Houston Industries Power Generation and NorAm Energy Services (HIPG/NES)
Term:	Five years starting June 1, 2001 and ending May 31, 2006
Capacity:	The following two capacity divisions apply: 1) 500 MWs for the period of June, 1 through September, 30 for each year in the Term of the agreement . 2) 200 MWs for the periods of January, 1 through May, 31 and October, 1 through December, 31 for each year in the Term of the agreement.
Delivery Point:	MPS Pleasant Hill Substation / MPS Interconnects
Capacity Price:	\$8.42/kW-mo for 500 MWs supplied in the June, 1 through September, 30 period specified above. \$4.21/kW-mo for 200 MWs supplied in the January, 1 through May, 31 and October, 1 through December, 31 periods specified above. The Capacity Prices include the cost of a 16 inch lateral pipeline to serve the generating facility.
Energy Price:	For all hours, MPS will have the option to call on the Energy at \$0.75/MWh plus the product of a 10,600 Btu/kWh heat rate and the natural gas fuel cost. HHV
Flexibility:	MPS has full dispatch rights to purchased Capacity limited only by the scheduling provisions below and the operational constraints of the unit (such as, but not limited to, a 4 hour minimum run time).
Fuel:	Natural gas supply and transportation will be managed by Seller. Seller will supply fuel at a mutually acceptable index, adjusted for delivery to the generating facility, along with a fixed charge for six Summer months of Firm Transportation. Seller will not maintain Firm Transportation for natural gas for the generating facility in the November through April period.
Unit Starts:	MPS will not be charged for the first 50 starts per contract year. MPS will be charged \$2,500 per start for the second 50 starts per contract year. However, should MPS request more than 100 starts per contract year,

MPS will be subject to paying incremental increases in maintenance and operating costs.

Scheduling: MPS will notify Seller of total planned output and number of starts by 9:00 AM Central Prevailing Time (CPT) one business day prior to flow so that fuel can be procured and transported.

If MPS provides a schedule after the 9:00 AM deadline, the gas price component of the Energy Price will be based on actual purchase cost and actual production from the unit will be conditioned on fuel availability.

Availability: The development plan envisions using proven technology which has historically attained very high availability levels. Availability targets will be set following further development effort. Seller envisions targets of 98% for all hours during the four Summer months. To provide appropriate operational incentives, the capacity payment will be adjusted (up or down) based upon actual performance relative to a specific target during the four Summer months of June through September.

Operations: HIPG will be responsible for managing operations and maintenance in accordance with generally accepted utility practices. MPS and Seller will cooperate to set scheduled maintenance outages. MPS will provide an on-site operations staff to Seller under a separate agreement.

Transmission: MPS will cooperate with Seller to accelerate the planned connection of the Pleasant Hill Substation to the 345 kv system.

Site: Under separate agreement, Seller will acquire approximately 70 acres of land near the Pleasant Hill Substation from MPS for approximately $3000 per acre.

Resale: In periods where MPS has not scheduled the Energy, Seller will have the right to sell the Energy.

Credit Support: The Seller's contract obligations are backed by a multi-billion dollar corporation with an investment grade rating. MPS's contract obligations are backed by ___________.

Note: If MPS provides fuel to the facility under a tolling arrangement, Seller will require access to Incremental Firm Transportation of natural gas for:

(a) Any Energy sales in excess of the Capacity specified above contracted for by MPS

(b) Energy sales by Seller when MPS does not call on its Energy

(c) Energy sales from this facility after the termination of this five-year agreement, if it is not renewed by both parties.

This document is not intended to create a binding offer or contract of purchase and sale of electric power or natural gas between MPS and Seller. Moreover, this document does not in any way whatsoever obligate either of the parties to enter into any agreements or to proceed with any possible relationship or transaction. The terms and conditions set forth above are subject to negotiation, completion and incorporation into and the execution by both parties of a definitive agreement. Either party may terminate discussions and/or negotiations regarding this document at any time.

Michael L. McInnis
Senior Vice President

NP Energy Inc.
3650 National City Tower
101 South Fifth Street
Louisville, Kentucky 40202

502.560.5312
502.560.5310 Fax
mmcinnis@npenergy.com

January 7, 1999

Mr. Robert W. Holzwarth
Vice President and General Manager
Utilicorp Energy Group
10700 East 350 Highway
Kansas City, MO 64138

Dear Mr. Holzwarth:

Please be advised that NP Energy ("NPE") assigned all of its rights, respecting the NPE power generation proposal to Missouri Public Service, to Houston Power Generation, Inc. on November 2, 1998. Should you have any questions concerning this assignment, please contact me at (502) 560-5312.

Very truly yours,

cc: T. P. Naulty, Houston Industries

NP Energy

Jack L. Farley, Jr.
Vice President.
Marketing

NP Energy Inc.
3650 National City Tower
101 South Fifth Street
Louisville, Kentucky 40202

502.560.5340
502.560.5310 Fax
jfarley@npenergy.com

July 2, 1998

Kiah Harris
Manager – Business Analysis & Consulting
Burns & McDonnell
9400 Ward Parkway
Kansas City, MO 64114

Subject: Response to Resource Specific Capacity & Energy for Missouri Public Service

Dear Mr. Harris:

NP Energy Inc. ("NPE") is pleased to present this 3-year proposal to provide 100 MW of capacity and energy to Missouri Public Service ("MPS"). This proposal provides MPS capacity at an attractive price, and energy at market rates. NPE is prepared to discuss other alternatives, such as extension options or a different quantity, if this base proposal is of interest to MPS.

The capacity that NPE is bidding in this proposal will be supplied through its contract with a plant that will be built in the Public Service Company of Oklahoma's control area. NPE is entering into a power purchase and sale agreement with the developers, pursuant to which NPE will have the exclusive right to purchase all of the output. The expected commencement date of plant's operations is June 1, 2001. If MPS is interested in this proposal, NPE will provide more information regarding the project and the developers. This proposal, and any ultimate purchase and sale agreement, is contingent upon successful completion of the plant.

NPE is a leading power marketer, active in all markets throughout the U.S. NPE is a venture between an employee group and National Power PLC of Great Britain. More information concerning NPE and National Power is included in the attached information.

This proposal is subject to the successful completion of due diligence, the successful negotiation, approval, and execution of a mutually agreeable definitive agreement, and NP Energy Inc. Board of Director approval. In addition, this proposal is contingent upon the plant being built.

Thank you in advance for your consideration of our proposal. Any questions should be directed to the undersigned at (502) 560-5366.

Sincerely,

Attachments

NP Energy Inc.
Proposal Prepared for MPS Resource Specific RFP
July 2, 1998

TIME PERIOD:

Start Date:	June 1, 2001
End Date:	May 31, 2004

CAPACITY:

SPP Accredited: Yes
Quantity: 100 MW
Price: $2.50/kW-month; no escalation

ENERGY PRICE:

MPS will have the ability to buy energy at market-based prices during all hours of the term

LOCATION

The capacity resource is located within the Public Service Company of Oklahoma's control area; The energy will be delivered to NPE's choice of MPS interface (or load control aggregate)

SCHEDULING:

MPS must notify NPE by 8:00 AM CPT the day prior to delivery for day-ahead schedules, or by 30 minutes prior to the hour of delivery for hourly schedules

TRANSMISSION:

If MPS chooses to reserve firm transmission associated with the capacity, an additional fee of $3.40/MWh plus 4% losses will be required (under current SPP tariff).

BUYOUT PROVISION:

MPS has the sole and exclusive right to buyout the contract at a fixed fee no later than a specific date (see dates and fees below). If MPS elects a buyout then MPS pays the buyout fee with 15 days and thereafter would not receive the capacity rights and would not pay the capacity price.

June 1, 2002:	$3,000,000
June 1, 2003	$1,500,000

10750 East 350 Highway
P.O. Box 11739
Kansas City, Missouri 64138

November 6, 1998

UTILICORP UNITED
ENERGYONE

Sherry M. Perchik
NP Energy
3650 National City Tower
Louisville KY 40202

RE: Power Supply RFP for Missouri Public Service issued by UtiliCorp United Inc.

Dear Sherry:

As you know, your firm's proposal was one of eight received by UtiliCorp in response to the above referenced RFP. In my August 25th letter I indicated that at that time UtiliCorp had planned to complete its analysis of the proposals by mid-September. Due to both internal and external circumstances the analysis was not completed as contemplated. UtiliCorp will now complete its analysis by mid-December.

The purpose of this letter is to:

1) Determine if your firm continues to be interested in providing power supply resources to Missouri Public Service (MPS).
2) Provide an opportunity for interested bidders to update or otherwise modify their original proposal.

Please contact me as soon as possible if your firm continues to have an interest in providing power supply resources to MPS so that the details of your proposal may be finalized.

In order for your firm's proposal to continue to be considered, a response to this letter must be received no later than 5:00 PM, November 13, 1998.

Sincerely yours,

Frank A. DeBacker

Frank A. DeBacker
Phone: (816) 936-8639
Fax: (816) 936-8695
Email: fdebacke2@utilicorp.com

NP Energy

NP Energy Inc.
3650 National City Tower
101 South Fifth Street
Louisville, Kentucky 40202

502.560.5300
502.560.5310 Fax

September 4, 1998

Frank A. DeBacker
Utilicorp
10700 East 350 Highway
Kansas City, Missouri 64138

Dear Frank:

In response to your letter dated August 25, 1998, NP Energy would like to submit the following proposal as a replacement for our original proposal. This proposal, which is detailed in the attached term sheet, is summarized here. NPE sells 200-300 MWs of capacity to MPS for a 5-year term. MPS has the option to call energy at a heat rate of 10,600 btu/kWh. The energy is unit firm with a guaranteed equivalent availability of 90%, and no less than 98% in the summer months.

This proposal is based upon NPE or a qualified developer building generation. While we are confident in our analysis and the underlying fundamentals, we would like to stress that this proposal is contingent upon numerous site specific and equipment specific factors. If this proposal is of interest to you, we are prepared to quickly finalize our offer.

The consummation of this transaction is subject to the successful negotiation, approval and execution of a mutually agreeable definitive agreement, and NPE Board of Directors approval. As the market is constantly changing, NPE will advise you of any market fluctuations which may affect NPE's pricing.

Please feel free to call me with any questions at (502)560-5366. I look forward to talking with you. I will be out of the office the week of September 7th, but my colleague Terry Naulty will be available should you have any questions during that time. He can be reached at (502)560-5361.

Regards,

FAX 1-502-560-5310

Sherry M. Perchik
Regional Marketing Director

Attachments

CONFIDENTIAL

Capacity & Optional Peaking Energy Proposal
Prepared for Missouri Public Service by NP Energy Inc.
September 4, 1998

TIME PERIOD:

Start Date: June 1, 2001
End Date: May 31, 2006

FIXED CAPACITY PRICE:

SPP Accredited Capacity: Yes
Quantity: 200 – 300 MWs
Price: ~~$4.00~~/kw-month capacity payment; escalated at 2.5% per year
~$4.25 m 10/28/98

ENERGY PRICE (applies for all hours of term):

MPS will have the option to call energy at $1.00/MWh (escalates at 2%) plus the product of a heat rate of 10,600 btu/kWh (at most efficient point) times the fuel cost. MPS can supply the gas, or NPE can supply the gas. If NPE supplies the gas, MPS will pay either a) a mutually acceptable index, adjusted for delivery to the facility, if the power is scheduled by 10:00 AM CPT, or otherwise b) the actual gas cost for energy scheduled after 10:00 AM CPT and up until 1 hour prior to hour of flow

START/STOP COSTS

No charge will be assessed for the first 50 starts/stops per year. A $2,500 charge per start will be assessed thereafter

DELIVERY POINT/TRANSMISSION:

The facility will be connected to the MPS transmission system, and will deliver energy at transmission level voltages. NPE and MPS will work cooperatively to optimally site the facility

NATURE OF SERVICE:

Unit Firm

ENERGY AVAILABILITY:

Annual equivalent availability will be guaranteed to be no less than 90%, and no less than 98% (with 47% of MWh in on-peak hours) in the summer months of June – September

Southern Company

Southern Company
Energy Marketing L.P.
200 Westlake Park Blvd
Suite 200
Houston, Texas 77079

Tel 281 584.3900
800.334.2726
Fax 281.584.3901

SOUTHERN COMPANY
Energy to Serve Your World™

July 2, 1998

PRIVATE & CONFIDENTIAL

Kiah Harris
Manager, Business Analysis and Consulting
Burns & McDonnell
9400 Ward Parkway
Kansas City, Missouri 64114

Subject: Capacity and Energy Purchase Proposal

This document represents possible terms under which Southern Company Energy Marketing "SCEM" would provide capacity and energy to Missouri Public Service (MPS), a division of UtiliCorp United Inc. (UCU) per UCU's Request for Proposal (RFP) issued May 22, 1998. SCEM proposes to invest in capital assets to respond to MPS's capacity and energy needs from June 1, 2001 through May 31, 2004. SCEM would be receptive to extending the term of this agreement to complement MPS's future capacity and energy requirements. The assumptions and pricing scenarios are included on the following Attachments.

This proposal serves only to set out certain key terms and conditions that SCEM, based upon current market conditions, believes might be agreeable to MPS for inclusion in any final, mutually executed agreement on the subject transaction and, as such, does not constitute an offer nor does it obligate either party to proceed further. Certain additional, material terms would have to be negotiated and agreed upon before either SCEM or MPS would incur any contractual obligations to the other, and such further negotiations may necessitate changes to the terms and conditions set out in this letter.

SCEM appreciates the opportunity to work with MPS on this RFP and future opportunities. We welcome your comments regarding this proposal and any additional services you may require. Should you have questions, please contact me directly at (281) 584-3962.

Very truly yours,

Pat Mann
Manager

cc: Henderson Cosnahan
Ress Young

Pricing Proposal

Contract Term:	June 1, 2001 through May 31, 2004	
Capacity:	100 MW	
Price:	**Capacity**	\$2,650/MW-mo or \$31,800/MW-year in year 2001 dollars escalating @ 3.25%/year
	Energy	8350 BTU/kwh plus \$0.225/MWh variable O&M
	Gas	*First of month Index for Henry Hub as published in* "Inside FERC" plus \$0.04/MMBtu
	Transmission	Buyer may take delivery from our bus within Entergy's service territory.

Pricing Conditions

- Capacity and Energy is priced on a firm, unit contingent basis;
- *A minimum Energy take of 50% is assumed;*
- The following calculation will be used to calculate the energy price charge to MPS:

  (Heat Rate x Gas Price)/1000 + Variable O&M Cost = \$/MWh

  where: Heat Rate is in BTU/kwh
  Gas is in \$/MMBTU
  Variable O&M cost is in \$/MWh

- Pricing is based on a unit availability factor of 94%. SCEM will guarantee this availability.
- *Any energy purchased for MPS by SCEM to cover forced outages within the 94% unit availability* tolerance or any forced outages or transmission constraints that are out of SCEM's control due to conditions of force majeure will be priced at *procurement/market prices.* SCEM will exercise a good faith effort in securing energy at the most economic price.
- Energy provided to MPS by SCEM during scheduled outages or unscheduled outages outside of the 94% unit availability tolerance will be priced as quoted above. SCEM will provide MPS with an annual maintenance schedule.

Buyout Provision:	Buyer shall have the option to purchase their pro rata share of the asset at the then current book value upon June 1, 2002.
Scheduling:	Resource Start up costs - not applicable Minimum load factor & measuring period - 50% Annual Maximum load factor & measuring period - 100% of unit availability Minimum schedule block - 50 MW Initial schedule submittal procedure - Day ahead preschedule with written confirmation Subsequent schedule change procedure - 12 hour notice Energy Block Requirements - Standard On and Off Peak Blocks
Agreement:	SCEM and MPS agree to enter into a formal Sales and Purchase Agreement.
Confidentiality:	This proposal, the contents hereof, and the transaction contemplated hereby are confidential and will not be disclosed by either party (or their agents), without prior consent of the other party.

Southern Company
Energy Marketing L.P.
900 Westlake Park Blvd.
Suite 200
Houston, Texas 77079

Tel 281.584.3900
800.334.2726
Fax 281.584.3901

September 1, 1998

SOUTHERN COMPANY
Energy to Serve Your World™

UtiliCorp United
10700 East 350 Highway
Kansas City, Missouri 64138

Attn: Frank A. DeBacker

RE: Missouri Public Service RFP issued by UtiliCorp United Inc.

Dear Frank:

In response to your letter dated August 25,1998 , Southern Company Energy Marketing L.P. (SCEM) continues to be interested in providing power supply resources to Missouri Public Service (MPS) under the terms expressed in our offer.

Our proposal serves only to set out certain key terms and conditions that SCEM, based upon current market conditions, believes might be agreeable to UtiliCorp United for inclusion in any final, mutually executed agreement on the subject transaction. Certain additional, material terms would have to be negotiated and agreed upon before either SCEM or UtiliCorp United would incur any contractual obligations to the other, and such further negations may necessitate changes to the terms and conditions set out in this letter.

I look forward to working with you towards a final agreement. Please call David Cavazos at 281-584-3945 or myself at 281-584-3962 if you have any questions or comments regarding our offer.

Sincerely,

David H Cavazos

for Pat Mann
Manager

cc: Henderson Cosnahan
David Cavazos

a Vastar partnership

Chronology
of
Supply Side Resource Solicitation Process

May 22, 1998	Issued Request for Proposal for Supply Resources for June 1, 2000 to May 31, 2004.
July 3, 1998	Received eight proposals: Aquila Power — Basin Electric Cooperative Carolina Power & Light — LS Power, LLC New Century Energies — NorAm Energy Services, Inc. NP Energy Inc. — Southern Company
August 21, 1998	Initial evaluation of proposals completed by Burns & McDonnell. Results indicated that a self build EWG option supplemented with short term purchases for 2000/2001 offered the lowest cost option.
August 25, 1998	Requested that original bidders confirm their interest and update their proposals. All bidders with the exception of LS Power responded in the affirmative and either confirmed their original pricing or offered revised pricing. With the exception of New Century Energies, Aquila and Basin, all bidders stated that they were no longer able to meet a June 1, 2000 delivery date.
September 9, 1998	Executed letter of intent to purchase excess capacity from Sunflower Electric Cooperative.
September, 1998	Determined that only three cost effective supply options existed for the June, 2000 to May, 2001 period: Aquila, New Century Energies and Sunflower. The Basin proposal was not cost effective due to the high capacity charge.
September, 1998	UtiliCorp forms Merchant Energy Partners to develop and own Exempt Wholesale Generator (EWG) and Independent Power Producer (IPP) facilities.
November 3, 1998	Completed evaluation of the three cost effective supply resources available for the June, 2000 to May, 2001 period. Portfolio consisting of a mix of Sunflower and Aquila resources determined to be most cost effective.
November 6, 1998	Requested that bidders again confirm their interest and update their proposals. Established November 30, 1998 as due date for best and final offers. All bidders except Basin Electric, LS Power and Southern verbally indicated a continued interest. Carolina Power & Light and NP Energy subsequently withdrew their proposals.

Chronology
of
Supply Side Resource Solicitation Process

November, 1998	Carolina Power & Light decided that it could not commit resources without a long term agreement and withdrew from the bidding process. NP Energy decided that it could not commit resources due to its financial position and withdrew its proposal in favor of Houston Industries.
November 9, 1998	Received contract from Aquila Power for 135 MW of peaking capacity for period June 1, 2000 to September 30, 2000.
November 30, 1998	Received revised proposals from Aquila Power/Merchant Energy Partners and Houston Industries for the June, 2001 to May, 2006 period.
December 17,1998	Executed contract to purchase excess capacity from Sunflower.
December 21, 1998	Contacted Houston Industries and advised them that their proposal was not cost effective as structured and requested that they consider revising their proposal.
December 29, 1998	Met with Houston Industries to discuss MPS' capacity needs and provide information which would allow them to improve their proposal.
January 4, 1998	Met with Merchant Energy Partners to begin the process of clarifying and solidifying the terms and conditions of their proposal.
January 6, 1999	Met with Houston Industries and received their revised proposal. Received confirmation that Merchant Energy Partners would replace Aquila Power as the owner of the proposed EWG and would be the entity contracting with MPS.
January 7, 1999	Completed evaluation of Houston Industries proposal. Received notice that NP Energy had assigned its proposal to Houston Industries.
January 11, 1999	Meeting with UCU management Group to discuss status of MPS power supply.
January 12, 1999	Merchant Energy Partners submitted revisions to their proposal.

Chronology
of
Supply Side Resource Solicitation Process

January 13, 1999	Notified Houston Industries that their proposal was not competive at present pricing levels and terms and conditions (ie: five year term with no option to reduce purchase amount).
January 14, 1999	Houston responded that they were not able to improve their offer.
January 15, 1999	Notified Houston Industries that they were not successful bidder. Notified Merchant Energy Partners that their proposal was selected as preferred supply option subject to successful negotiation of contract.
January 16, 1999 to Present	Negotiated final terms and conditions of power supply agreement with Merchant Energy Partners.

Burns & McDonnell 100 1898 • 1998

February 1, 1999

Mr. Frank DeBacker
Vice President - Fuel & Purchased Power
Utilicorp United
10750 East 350 Highway
Kansas City, Missouri 64138

Report on the Evaluation of Power Supply Proposals

Mr. DeBacker:

This letter summarizes the results of Burns & McDonnell's evaluation of power supply proposals. UtiliCorp United (UCU) provided the proposals and updated offers from Houston Industries (HI) and Merchant Energy Partners (MEP).

The objective of the evaluation was to verify that the information from the proposals had been accurately input into the model. The evaluation was also performed to determine the power supply option which, when combined with UCU's existing resources, would result in the lowest total cost of power supply for UCU during the evaluation period of June 1, 2000 to May 31, 2005. The evaluation was performed using the RealTime production cost modeling software written by the Emelar Group and utilized the RealTime database of existing power supply resources provided by UCU.

Burns & McDonnell verified that the information provided by UCU had been correctly input into the model. Assumptions made in the evaluation of the offers were provided by UCU and included the natural gas price forecasts, spot energy market price forecasts, and energy sales price forecasts. Burns & McDonnell has reviewed these assumptions and determined that they are reasonable.

The results of the RealTime modeling are shown on the attached tables. Both proposals were modeled under a base, low, and high gas price forecast and a base, low, and high energy market price forecast. All cases were run with and without the sale of energy not required by UCU. The energy to be sold could be provided by any available resources in each case modeled.

As shown in the tables, the total expenses of the two proposals were very similar across all of the cases run. The NPV of total costs for the MEP option is slightly less than the HI option in all but one case. The HI proposal was less expensive in the case involving the base gas price forecast, low market energy prices, and no off-system sales.

ENGINEERS • ARCHITECTS • CONSULTANTS
9400 Ward Parkway
Kansas City, Missouri 64114-3319
Tel: 816 333-9400
Fax: 816 333-3690

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We appreciate the opportunity to be of service to Utilicorp United. We would also like to express our appreciation for the cooperation we received from you and Mr. Roger Parkes during the evaluation process. If there are any aspects of the analyses that you wish to discuss, please do not hesitate to call us.

Sincerely,

James M. Flucke

James M. Flucke, P.E.
Project Manager

Missouri Power Supply
Bid Comparison
6/1/2000 - 5/31/2005
$x1,000

		Annual Cost $x1,000					NPV
	From>	Jun-00	Jun-01	Jun-02	Jun-03	Jun-04	Jun-00
	To>	May-01	May-02	May-03	May-04	May-05	May-05
Without Off System Sales							
Base Gas & Mkt							
Merchant Energy Partners		108,388	130,053	135,381	143,952	154,103	530,017
Houston Industries		108,388	129,074	136,181	145,432	156,081	532,248
Low Gas & Mkt							
Merchant Energy Partners		107,201	128,131	133,679	141,514	150,536	521,700
Houston Industries		107,201	127,071	133,707	142,439	152,179	522,611
High Gas & Mkt							
Merchant Energy Partners		109,286	131,741	136,817	145,969	157,239	537,054
Houston Industries		109,287	130,352	138,055	147,781	159,531	539,738
Base Gas & High Mkt							
Merchant Energy Partners		109,286	131,611	136,202	144,902	155,416	534,428
Houston Industries		109,287	130,372	137,863	147,227	158,542	538,522
Base Gas & Low Mkt							
Merchant Energy Partners		107,201	128,216	134,081	142,533	152,026	523,854
Houston Industries		107,201	127,093	133,884	142,788	152,650	523,348
With Off System Sales							
Base Gas & Mkt							
Merchant Energy Partners		104,398	124,280	125,783	135,176	145,695	501,582
Houston Industries		104,496	123,971	132,218	141,965	152,742	516,301
Low Gas & Mkt							
Merchant Energy Partners		104,900	124,198	127,032	135,426	144,548	502,371
Houston Industries		105,051	123,833	131,134	140,080	149,887	512,508
High Gas & Mkt							
Merchant Energy Partners		103,334	123,486	123,798	134,399	146,379	498,234
Houston Industries		103,366	122,870	132,193	143,092	155,022	516,671
Base Gas & High Mkt							
Merchant Energy Partners		103,334	123,245	122,774	132,659	143,683	494,100
Houston Industries		103,366	122,768	131,681	142,090	153,522	514,421
Base Gas & Low Mkt							
Merchant Energy Partners		104,900	124,319	127,710	136,885	146,458	505,385
Houston Industries		105,051	123,918	131,452	140,701	150,685	513,833

Merchant Energy Partners
Annual Ownership and Operating Cost
$x1,000

Annual Fixed Cost

From>	Jun-00	Jun-01	Jun-02	Jun-03	Jun-04
To>	May-01	May-02	May-03	May-04	May-05
Aquila Capacity Payment	4,866				
MEP Capacity Payment		17,696	27,660	27,660	27,660
SEC Capacity Payment	7,566	6,693			
Union Electric Capacity Payment	7,176				
Long Term Peaking Capacity Cost					
Short Term Peaking Capacity Cost				2,837	6,397
Gas Reservation Cost		6,890	6,890	6,890	6,890
Total Fixed Costs	19,608	31,279	34,550	37,387	40,947

Total Annual Supply Cost

Without Off System Sales					
MWh $ w/Base Gas & Mkt	88,779	98,774	100,831	106,565	113,157
Total Cost	108,388	130,053	135,381	143,952	154,103
MWh $ w/Low Gas & Mkt	87,592	96,852	99,129	104,127	109,589
Total Cost	107,201	128,131	133,679	141,514	150,536
MWh $ w/ High Gas & Mkt	89,678	100,462	102,267	108,582	116,293
Total Cost	109,286	131,741	136,817	145,969	157,239
MWh $ w/Base Gas & High Mkt	89,678	100,332	101,652	107,515	114,469
Total Cost	109,286	131,611	136,202	144,902	155,416
MWh $ w/Base Gas & Low Mkt	87,592	96,937	99,531	105,146	111,079
Total Cost	107,201	128,216	134,081	142,533	152,026
With Off System Sales					
MWh $ w/Base Gas & Mkt	84,789	93,001	91,233	97,790	104,748
Total Cost	104,398	124,280	125,783	135,176	145,695
MWh $ w/Low Gas & Mkt	85,292	92,919	92,482	98,040	103,601
Total Cost	104,900	124,198	127,032	135,426	144,548
MWh $ w/ High Gas & Mkt	83,725	92,207	89,248	97,012	105,433
Total Cost	103,334	123,486	123,798	134,399	146,379
MWh $ w/Base Gas & High Mkt	83,725	91,966	88,224	95,272	102,736
Total Cost	103,334	123,245	122,774	132,659	143,683
MWh $ w/Base Gas & Low Mkt	85,292	93,040	93,160	99,498	105,511
Total Cost	104,900	124,319	127,710	136,885	146,458

Houston Industries
Annual Ownership and Operating Cost
$x1,000

			Annual Fixed Cost		
From>	Jun-00	Jun-01	Jun-02	Jun-03	Jun-04
To>	May-01	May-02	May-03	May-04	May-05
Houston Capacity Payment		23,576	23,576	23,576	23,576
Aquila Capacity Payment	4,866				
SEC Capacity Payment	7,566				
Union Electric Capacity Payment	7,176				
Long Term Peaking Capacity Cost					
Short Term Peaking Capacity Cost				2,837	6,397
Gas Reservation Cost		8,755	8,755	8,755	8,755
Total Fixed Costs	19,608	32,331	32,331	35,168	38,728

			Total Annual Supply Cost		
Without Off System Sales					
MWh $ w/Base Gas & Mkt	88,780	96,743	103,850	110,264	117,353
Total Cost	108,388	129,074	136,181	145,432	156,081
MWh $ w/Low Gas & Mkt	87,592	94,740	101,375	107,271	113,451
Total Cost	107,201	127,071	133,707	142,439	152,179
MWh $ w/ High Gas & Mkt	89,678	98,021	105,724	112,613	120,803
Total Cost	109,287	130,352	138,055	147,781	159,531
MWh $ w/Base Gas & High Mkt	89,678	98,041	105,531	112,059	119,814
Total Cost	109,287	130,372	137,863	147,227	158,542
MWh $ w/Base Gas & Low Mkt	87,592	94,761	101,553	107,620	113,922
Total Cost	107,201	127,093	133,884	142,788	152,650
With Off System Sales					
MWh $ w/Base Gas & Mkt	84,888	91,639	99,886	106,797	114,014
Total Cost	104,496	123,971	132,218	141,965	152,742
MWh $ w/Low Gas & Mkt	85,442	91,501	98,802	104,912	111,159
Total Cost	105,051	123,833	131,134	140,080	149,887
MWh $ w/ High Gas & Mkt	83,757	90,539	99,861	107,924	116,293
Total Cost	103,366	122,870	132,193	143,092	155,022
MWh $ w/Base Gas & High Mkt	83,757	90,437	99,349	106,922	114,794
Total Cost	103,366	122,768	131,681	142,090	153,522
MWh $ w/Base Gas & Low Mkt	85,442	91,587	99,120	105,533	111,957
Total Cost	105,051	123,918	131,452	140,701	150,685

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August 21, 1998

Mr. Frank DeBacker
Vice President - Fuel & Purchased Power
Utilicorp United
10750 East 350 Highway
Kansas City, Missouri 64138

Report on the Evaluation of Power Supply Proposals

Mr. DeBacker:

This letter summarizes the results of Burns & McDonnell's evaluation of power supply proposals made in response to the request for proposals (RFP) issued by Utilicorp United (UCU). The proposals were opened on July 6, 1998 with representatives of UCU and Burns & McDonnell in attendance. Proposals were received from the following companies in alphabetical order:

- Aquila Power Corporation (Aquila)
- Basin Electric Power Cooperative (Basin)
- Carolina Power & Light Company (CP&L)
- LS Power, LLC (LS Power)
- NorAm Energy Services (NorAm)
- NP Energy, Inc. (NP Energy)
- Southern Company Energy Marketing (Southern)
- Southwestern Public Service Company (SPS)

The objective of the evaluation was to determine the power supply option or combination of power supply options which, when combined with UCU's existing resources, would result in the lowest total cost of power supply for UCU during the evaluation period of June 1, 2000 to May 31, 2004. The evaluation was performed using the RealTime production cost modeling software written by the Emelar Group and utilized the RealTime database of existing power supply resources provided by UCU. Assumptions made in the evaluation of the offers are listed in Table 1. This list of assumptions includes all information used in the modeling that was not specifically provided in the offers.

Combinations of the power supply options were made as necessary to minimize total expenses and meet the capacity requirements of UCU in the evaluation period. The timing and combinations of offers for the lowest cost cases are shown in Table 2 at the end of the report. Each case was run under two different scenarios. The first scenario allowed the energy not required by UCU to be sold. The sale price used in the model for

ENGINEERS • ARCHITECTS • CONSULTANTS
9400 Ward Parkway
Kansas City, Missouri 64114-3319
Tel: 816 333-9400
Fax: 816 333-3690
http://www.burnsmcd.com

this surplus energy was the spot market price of energy less $2.00/MWh. The spot market energy price forecast and the adjustment for the energy sales prices were provided by UCU. The energy to be sold could be provided by any available resources in each case modeled. The second scenario did not take into account the sale of surplus energy.

Table 3 shows the results of the RealTime modeling for the scenario with energy sales. The cases shown in the table represent the lowest cost cases developed by Burns & McDonnell. The lowest cost option includes a combination of purchases from Aquila, SPS, and a 55 MW unit-contingent purchase in the first twelve months of the study period and the addition of 500 MW of combined cycle capacity by UCU on June 1, 2001. This combination of resources results in total expenses of $391,167,001, approximately $25 million less than the next least expensive case which includes the same purchases and combined cycle units offered by LS Power.

The relative cost rankings change considerably if sales are not taken into consideration as shown in Table 4. The lowest cost case without sales of excess energy includes purchases from Aquila, SPS, and a 55 MW unit-contingent purchase in the first twelve months of the evaluation period and purchases from CP&L, Southern, NP Energy, and Aquila over the remaining three years. The case including the addition of combined cycle units by UCU has total expenses of approximately $7 million more than the least cost case over the evaluation period.

We appreciate the opportunity to be of service to Utilicorp United. We would also like to express our appreciation for the cooperation we received from you and Mr. Roger Parkes during the evaluation process. If there are any aspects of the analyses that you wish to discuss, please do not hesitate to call us.

Sincerely,

Daniel A. Froelich

Daniel A. Froelich, P.E.
Vice President

James M. Flucke

James M. Flucke, P.E.
Project Manager

Table 1
Assumptions Made for RealTime Modeling

Evaluation period - June 1, 2000 to May 31, 2004.
Capacity and demand forecasts for 2001-2004 provided by Utilicorp.
Spot market energy price forecast provided by Utilicorp.
MPS internal wheeling charges are assumed to the same for both generation built internal to the MPS transmission system and power delivered from outside the MPS transmission system.
MPS natural gas price forecast provided by MPS equals Henry Hub Index price forecast minus $0.09/mmBtu plus $0.35/mmBtu in transmission charges.
At the direction of Utilicorp, peaking capacity assumed to be available for $4.00/kW-mo.
Sales of excess energy were made at the spot market energy price less $2.00/MWh.
Information on 55 MW unit-contingent purchase provided by Utilicorp.

Aquila
Transmission charges of $1,997/MW-mo. based on present transmission charges of Entergy and Ameren.

Basin Electric Power Cooperative

Carolina Power & Light
Cost of natural gas assumed to be equal to Utilicorp's cost of natural gas.
Assumed contract could start on June 1, 2001.

LS Power
The effect of the 10-year contract beyond the evaluation period has not been taken into consideration.
Cost of natural gas assumed to be equal to Utilicorp's cost of natural gas.
Assumed Availability Adjustment Factor equal to one for the second and third years of the contract.
Gross Domestic Price Deflator assumed to equal three percent.

NorAm
Transmission charge of $998/MW-mo. based on present Ameren transmission charges and $1.37/MWh provided by NorAm. .

NP Energy
Market based hourly energy price forecast provided by Utilicorp.
Transmission charge of $2,497/MW-mo. provided by Utilicorp.
Assumed losses of 4.2% for both capacity and energy price provided by Utilicorp.
Energy price equals market based price forecast plus $3.40/MWh in transmission charges plus 4.2% losses.

Southern Company
Cost of natural gas assumed to be equal to Henry Hub Index price forecast provided by Utilicorp.
Transmission charges of $1,997/MW-mo. based on present transmission charges of Entergy and Ameren.

SPS
Option A assumed to be available for a one-year term based on discussions with Utilicorp.
Assumed transmission charges equal to $4,033/MW-mo. provided by Utilicorp.
Capacity charges not included in model but were added to the total expenses on the "RealTime Modeling Results" spreadsheet.
Assumed losses of 8.05% for both capacity and energy provided by Utilicorp.

Utilicorp United
Fuel costs based on heat rate curves and natural gas price forecasts provided by Utilicorp.
Combined-cycle capacity addition of 500 MW on June 1, 2001.
Capacity charge of $5.50/kW-mo with no escalation assumed for CC units based on discussions with Utilicorp.
Operation & Maintenance cost forecast provided by Utilicorp.
Capacity charges not included in model but were added to the total expenses on the "RealTime Modeling Results" spreadsheet.

Table 2
Case 1 Description

Case 1		Evaluation Period			
		June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		Capacity Utilized (MW)			
LS Power	540		540	540	540
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100				
SPS A	75-100	75			
SPS Peak	25	25			
Basin	<=100				
NP Energy	100				
Southern	100				
CP&L	150				
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract					
Total Capacity Additions (MW)		255	540	540	540
Excess Capacity (MW)		0	135	100	60

Table 2 (Cont.)
Case 2 Description

Case 2		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		Capacity Utilized (MW)			
LS Power	540				
UCU	500		500	500	500
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100				
SPS A	75-100	75			
SPS Peak	25	25			
Basin	<=100				
NP Energy	100				
Southern	100				
CP&L	150				
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract					
Total Capacity Additions (MW)		255	500	500	500
Excess Capacity (MW)		0	95	60	20

Table 2 (Cont.)
Case 3 Description

Case 3		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		Capacity Utilized (MW)			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100		100	100	100
SPS A	75-100	75	100	100	100
SPS Peak	25	25			
Basin	<=100				
NP Energy	100				
Southern	100		100	100	100
CP&L	150		150	150	150
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract					30
Total Capacity Additions (MW)		255	450	450	480
Excess Capacity (MW)		0	45	10	0

Table 2 (Cont.)
Case 4 Description

Case 4		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		Capacity Utilized (MW)			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100				
SPS A	75-100	75	100	100	100
SPS Peak	25	25			
Basin	<=100				
NP Energy	100		100	100	100
Southern	100		100	100	100
CP&L	150		150	150	150
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract					30
Total Capacity Additions (MW)		255	450	450	480
Excess Capacity (MW)		0	45	10	0

Table 2 (Cont.)
Case 4a Description

Case 4a		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		**Capacity Utilized (MW)**			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100		100	100	100
SPS A	75-100	75			
SPS Peak	25	25			
Basin	<=100				
NP Energy	100		100	100	100
Southern	100		100	100	100
CP&L	150		150	150	150
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract					30
Total Capacity Additions (MW)		255	450	450	480
Excess Capacity (MW)		0	45	10	0

Table 2 (Cont.)
Case 4b Description

Case 4b		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		Capacity Utilized (MW)			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100				
SPS A	75-100	75			
SPS Peak	25	25			
Basin	<=100				
NP Energy	100		100	100	100
Southem	100		100	100	100
CP&L	150		150	150	150
NORAM	100		100	100	100
Unit-Contingent Purchase	55	55			
Peaking Contract					30
Total Capacity Additions (MW)		255	450	450	480
Excess Capacity (MW)		0	45	10	0

Table 2 (Cont.)
Case 5 Description

Case 5		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		Capacity Utilized (MW)			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100		100	100	100
SPS A	75-100	75	100	100	100
SPS Peak	25	25			
Basin	<=100				
NP Energy	100		100	100	100
Southern	100				
CP&L	150		150	150	150
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract					30
Total Capacity Additions (MW)		255	450	450	480
Excess Capacity (MW)		0	45	10	0

Table 2 (Cont.)
Case 6 Description

Case 6		Evaluation Period June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		Capacity Utilized (MW)			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100		100	100	100
SPS A	75-100	75	100	100	100
SPS Peak	25	25			
Basin	<=100				
NP Energy	100		100	100	100
Southern	100		100	100	100
CP&L	150				
NORAM	100				
Unit-Contingent Purchase	55	55			
Peaking Contract			5	40	80
Total Capacity Additions (MW)		255	405	440	480
Excess Capacity (MW)		0	0	0	0

Table 2 (Cont.)
Case 7 Description

Case 7		Evaluation Period June, 2000 to May, 2001	 June, 2001 to May, 2002	 June, 2002 to May, 2003	 June, 2003 to May, 2004
Capacity Need (MW)		255	405	440	480
Offered Capacity (MW)		**Capacity Utilized (MW)**			
LS Power	540				
UCU	500				
Aquila 1a	100	100			
Aquila 1b	75	75			
Aquila 3	100		100	100	100
SPS A	75-100	75	100	100	100
SPS Peak	25	25			
Basin	<=100				
NP Energy	100				
Southern	100		100	100	100
CP&L	150				
NORAM	100		100	100	100
Unit-Contingent Purchase	55	55			
Peaking Contract			5	40	80
Total Capacity Additions (MW)		255	405	440	480
Excess Capacity (MW)		0	0	0	0

Table 3

RealTime Modeling Results with Sales

June 1, 2000 to May 31, 2004

Case	Contract	Capacity MW	Energy MWh	Cost $	Total *Purchases $*	Total *Sales $*	Total *Generations Cost $*	Total *Expense $*	% Above Least Expensive Case	$ Above Least Expensive Case
Case 1					$ 389,912,026	-$244,101,124	$ 270,450,846	$ 416,261,748	6.4%	$ 25,094,747
	LS Power Unit 1 (Online 2001)	270	5,503,419	$ 172,351,827						
	LS Power Unit 2 (Online 2001)	270	5,215,847	$ 166,023,916						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75	348,547	$ 16,082,792						
	(Peaking Capacity)	25	10,849	$ 1,720,833						
	Unit-Contingent Purchase	55	12,628	$ 3,126,081						
	Sales		-9,638,472	-$244,101,124						
Case 2					$ 56,009,906	-$229,989,146	$ 565,146,241	$ 391,167,001	0.0%	$ -
	Utilicorp Unit 1 (Online 2001)	250	5,263,141	$ 148,501,561						
	Utilicorp Unit 2 (Online 2001)	250	4,741,587	$ 138,812,149						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	103	$ 4,809,452						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,199						
	SPS Option A (Partial Requirement)	75	348,173	$ 16,074,017						
	(Peaking Capacity)	25	11,105	$ 1,728,457						
	Unit-Contingent Purchase	55	12,228	$ 3,110,389						
	Sales		-9,294,721	-$229,989,146						
Case 3					$ 258,759,280	-$115,277,263	$ 292,881,747	$ 436,363,764	11.6%	$ 45,196,763
	CP&L	150	272,064	$ 35,093,650						
	Southern	100	2,040,278	$ 59,698,798						
	Aquila Option 3	100	126	$ 24,370,535						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	122	$ 4,811,451						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,732,666	$ 97,758,915						
	(Peaking Capacity)	25	11,069	$ 1,730,085						
	Unit-Contingent Purchase	55	12,622	$ 3,123,522						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,607,503	-$115,277,263						
Case 4					$ 252,834,409	-$115,370,390	$ 292,799,355	$ 430,263,374	10.0%	$ 39,096,373
	CP&L	150	271,670	$ 35,078,240						
	Southern	100	2,035,607	$ 59,600,970						
	NP Energy	100	7,611	$ 18,626,909						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	168	$ 4,816,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,735,959	$ 97,822,864						
	(Peaking Capacity)	25	10,904	$ 1,726,183						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,609,387	-$115,370,390						
Case 4a					$ 207,034,425	-$76,232,010	$ 305,746,570	$ 436,548,985	11.6%	$ 45,381,984
	CP&L	150	296,929	$ 35,871,171						
	Southern	100	2,099,871	$ 60,988,898						
	NP Energy	100	19,298	$ 19,001,909						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	Aquila 3	100	131	$ 24,370,845						
	SPS Option A (Partial Requirement)	75	347,040	$ 16,050,715						
	(Peaking Capacity)	25	10,823	$ 1,721,288						
	Unit-Contingent Purchase	55	12,706	$ 3,128,333						
	Peaking Contract		0	$ 1,440,000						
	Sales		-3,081,867	-$76,232,010						
Case 4b					$ 245,656,954	-$104,544,438	$ 299,063,984	$ 440,176,500	12.5%	$ 49,009,499
	CP&L	150	289,141	$ 35,000,521						
	Southern	100	2,095,140	$ 60,891,338						
	NP Energy	100	6,746	$ 18,583,373						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	NorAm	100	1,524,514	$ 72,332,404						
	SPS Option A (Partial Requirement)	75	348,547	$ 16,082,792						
	(Peaking Capacity)	25	10,849	$ 1,720,933						
	Unit-Contingent Purchase	55	12,628	$ 3,126,081						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,071,935	-$104,544,438						
Case 5					$ 227,595,089	-$79,905,446	$ 302,832,926	$ 450,522,569	15.2%	$ 59,355,568
	CP&L	150	294,307	$ 35,788,707						
	Aquila Option 3	100	109	$ 24,368,588						
	NP Energy	100	15,118	$ 18,984,500						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	168	$ 4,816,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,736,056	$ 97,824,847						
	(Peaking Capacity)	25	10,904	$ 1,726,163						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 1,440,000						
	Sales		-3,267,595	-$79,905,446						
Case 6					$ 249,212,528	-$107,803,417	$ 292,866,910	$ 434,276,021	11.0%	$ 43,109,020
	Aquila Option 3	100	188	$ 24,374,724						
	NP Energy	100	13,800	$ 18,873,562						
	Southern	100	2,035,607	$ 59,600,952						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	168	$ 4,818,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,735,958	$ 97,822,884						
	(Peaking Capacity)	25	10,904	$ 1,726,163						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 6,000,000						
	Sales		-4,401,647	-$107,803,417						
Case 7					$ 297,070,015	-$140,445,134	$ 287,938,305	$ 444,563,186	13.7%	$ 53,396,185
	Southern	100	2,038,417	$ 59,658,506						
	Aquila Option 3	100	196	$ 24,377,567						
	NorAm	100	1,475,488	$ 71,142,954						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	28	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,736,170	$ 97,825,464						
	(Peaking Capacity)	25	10,823	$ 1,721,288						
	Unit-Contingent Purchase	55	12,708	$ 3,128,333						
	Peaking Contract		0	$ 6,000,000						
	Sales		-5,553,100	-$140,445,134						

Notes
SPS Option A Partial Requirement has a capacity of 75 MW for the first year and 100 MW for the last three years
SPS Option A was only taken for one year for cases 1, 2, 4a, and 4b
Peaking Contract includes a capacity charge of $4.00/MW-mo. for all capacity deficits

Table 4
RealTime Modeling Results without Sales
June 1, 2000 to May 31, 2004

Case	Contract	Capacity MW	Energy MWh	Cost $	Total Purchases $	Total Generations Cost $	Total Expense $	% Above Least Expensive Case	$ Above Least Expensive Case
Case 1					$ 247,482,085	$ 228,719,801	$ 476,201,886	4.9%	$ 22,182,486
	LS Power Unit 1 (Online 2001)	270	3,450,651	$ 128,875,814					
	LS Power Unit 2 (Online 2001)	270	1,159,977	$ 79,414,823					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (Parital Requirement)	75	175,698	$ 12,420,153					
	(Peaking Capacity)	25	10,918	$ 1,723,930					
	Unit-Contingent Purchase	55	9,776	$ 3,016,014					
Case 2					$ 44,330,926	$ 423,308,758	$ 467,639,684	3.0%	$ 13,620,284
	Utilicorp Unit 1 (Online 2001)	250	3,380,441	$ 120,708,810					
	Utilicorp Unit 2 (Online 2001)	250	1,379,094	$ 77,788,906					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	147	$ 4,814,017					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,199					
	SPS Option A (Parital Requirement)	75	174,554	$ 12,397,030					
	(Peaking Capacity)	25	11,078	$ 1,731,887					
	Unit-Contingent Purchase	55	9,850	$ 3,018,109					
Case 3					$ 196,163,051	$ 264,990,950	$ 461,154,001	1.6%	$ 7,134,601
	CP&L	150	69,963	$ 28,773,330					
	Southern	100	940,495	$ 36,572,069					
	Aquila Option 3	100	153	$ 24,373,182					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (Parital Requirement)	75/100	1,422,437	$ 71,758,138					
	(Peaking Capacity)	25	10,905	$ 1,723,749					
	Unit-Contingent Purchase	55	9,891	$ 3,019,083					
	Peaking Contract		0	$ 1,440,000					
Case 4					$ 190,167,020	$ 264,956,444	$ 455,123,464	0.2%	$ 1,104,064
	CP&L	150	67,346	$ 28,689,735					
	Southern	100	935,112	$ 36,457,450					
	NP Energy	100	8,090	$ 18,644,079					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (Parital Requirement)	75/100	1,423,251	$ 71,770,828					
	(Peaking Capacity)	25	10,895	$ 1,724,424					
	Unit-Contingent Purchase	55	9,921	$ 3,020,939					
	Peaking Contract		0	$ 1,440,000					
Case 4a					$ 173,655,923	$ 280,363,477	$ 454,019,400	0.0%	$ -
	CP&L	150	128,230	$ 30,595,187					
	Southern	100	1,272,189	$ 43,749,960					
	NP Energy	100	19,468	$ 19,007,529					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	Aquila 3	100	131	$ 24,370,845					
	SPS Option A (Parital Requirement)	75	173,579	$ 12,375,423					
	(Peaking Capacity)	25	10,895	$ 1,724,424					
	Unit-Contingent Purchase	55	9,921	$ 3,020,939					
	Peaking Contract		0	$ 1,440,000					
Case 4b					$ 190,348,728	$ 270,494,040	$ 460,842,768	1.5%	$ 6,823,368
	CP&L	150	65,557	$ 28,633,893					
	Southern	100	1,279,851	$ 43,918,072					
	NP Energy	100	6,758	$ 18,593,725					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	NorAm	100	647,710	$ 51,208,572					
	SPS Option A (Partial Requirement)	75	175,698	$ 12,420,153					
	(Peaking Capacity)	25	10,918	$ 1,723,930					
	Unit-Contingent Purchase	55	9,776	$ 3,016,014					
	Peaking Contract		0	$ 1,440,000					
Case 5					$ 191,200,852	$ 278,177,382	$ 469,378,234	3.4%	$ 15,358,834
	CP&L	150	125,345	$ 30,504,582					
	Aquila Option 3	100	131	$ 24,370,845					
	NP Energy	100	18,990	$ 18,991,617					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (Parital Requirement)	75/100	1,525,643	$ 73,874,603					
	(Peaking Capacity)	25	10,895	$ 1,724,424					
	Unit-Contingent Purchase	55	9,921	$ 3,020,939					
	Peaking Contract		0	$ 1,440,000					
Case 6					$ 192,988,455	$ 265,108,518	$ 458,096,973	0.9%	$ 4,077,573
	Aquila Option 3	100	196	$ 24,377,567					
	NP Energy	100	14,527	$ 18,899,618					
	Southern	100	935,112	$ 36,457,442					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (Parital Requirement)	75/100	1,423,244	$ 71,770,683					
	(Peaking Capacity)	25	10,895	$ 1,724,424					
	Unit-Contingent Purchase	55	9,921	$ 3,020,939					
	Peaking Contract		0	$ 6,000,000					
Case 7					$ 214,582,569	$ 257,622,027	$ 472,204,596	4.0%	$ 18,185,196
	Southern	100	941,572	$ 36,595,807					
	Aquila Option 3	100	196	$ 24,377,567					
	NorAm	100	390,664	$ 44,985,611					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (Parital Requirement)	75/100	1,426,397	$ 71,834,565					
	(Peaking Capacity)	25	10,895	$ 1,724,424					
	Unit-Contingent Purchase	55	9,921	$ 3,020,939					
	Peaking Contract		0	$ 6,000,000					

Notes

SPS Option A Partial Requirement has a capacity of 75 MW for the first year and 100 MW for the last three years

SPS Option A was only taken for one year for cases 1, 2, 4a, and 4b

Peaking Contract includes a capacity charge of $4.00/MW-mo. for all capacity deficits

"Look Date" 1-Dec-98

Greenwood Gas Commodity Cost

1999	Strip Price	Est Basis	WNG	Fuel	Transport	ACA/GRI	LDC	Burner Tip
January	1.99	-0.13	1.858	0.045884	0.05	0.01		1.964
February	2.02	-0.13	1.885	0.04655	0.05	0.01		1.992
March	2.01	-0.13	1.88	0.046427	0.05	0.01		1.986
April	2.00	-0.13	1.87	0.04618	0.05	0.01		1.976
May	2.02	-0.13	1.885	0.04655	0.05	0.01		1.992
June	2.02	-0.13	1.888	0.046624	0.05	0.01		1.995
July	2.03	-0.13	1.9	0.046921	0.05	0.01		2.007
August	2.04	-0.13	1.912	0.047217	0.05	0.01		2.019
September	2.06	-0.13	1.925	0.047538	0.05	0.01		2.033
October	2.11	-0.13	1.98	0.048896	0.05	0.01		2.089
November	2.25	-0.13	2.122	0.052403	0.05	0.01		2.234
December	2.40	-0.13	2.275	0.056181	0.05	0.01		2.391

2000	Strip Price	Est Basis	WNG	Fuel	Transport	ACA/GRI	LDC	Burner Tip
January	2.46	-0.13	2.335	0.057663	0.05	0.01		2.453
February	2.36	-0.13	2.23	0.055070	0.05	0.01		2.345
March	2.25	-0.13	2.12	0.052354	0.05	0.01		2.232
April	2.17	-0.13	2.04	0.050378	0.05	0.01		2.150
May	2.14	-0.13	2.01	0.049637	0.05	0.01		2.120
June	2.14	-0.13	2.007	0.049563	0.05	0.01		2.117
July	2.14	-0.13	2.014	0.049736	0.05	0.01		2.124
August	2.15	-0.13	2.021	0.049909	0.05	0.01		2.131
September	2.15	-0.13	2.025	0.050008	0.05	0.01		2.135
October	2.18	-0.13	2.055	0.050749	0.05	0.01		2.166
November	2.32	-0.13	2.188	0.054033	0.05	0.01		2.302
December	2.46	-0.13	2.333	0.057614	0.05	0.01		2.451

"Look Date" 1-Dec-98

RG3 Gas Commodity Cost

1999	Strip Price	Est Basis	WNG	Fuel	Transport	ACA/GRI	LDC	Burner Tip
January	1.99	-0.13	1.858	0.045884	0.25	0.01		2.164
February	2.02	-0.13	1.885	0.04655	0.25	0.01		2.192
March	2.01	-0.13	1.88	0.046427	0.25	0.01		2.186
April	2.00	-0.13	1.87	0.04618	0.25	0.01		2.176
May	2.02	-0.13	1.885	0.04655	0.25	0.01		2.192
June	2.02	-0.13	1.888	0.046624	0.25	0.01		2.195
July	2.03	-0.13	1.9	0.046921	0.25	0.01		2.207
August	2.04	-0.13	1.912	0.047217	0.25	0.01		2.219
September	2.06	-0.13	1.925	0.047538	0.25	0.01		2.233
October	2.11	-0.13	1.98	0.048896	0.25	0.01		2.289
November	2.25	-0.13	2.122	0.052403	0.25	0.01		2.434
December	2.40	-0.13	2.275	0.056181	0.25	0.01		2.591

2000	Strip Price	Est Basis	WNG	Fuel	Transport	ACA/GRI	LDC	Burner Tip
January	2.46	-0.13	2.335	0.057663	0.25	0.01		2.653
February	2.36	-0.13	2.23	0.055070	0.25	0.01		2.545
March	2.25	-0.13	2.12	0.052354	0.25	0.01		2.432
April	2.17	-0.13	2.04	0.050378	0.25	0.01		2.350
May	2.14	-0.13	2.01	0.049637	0.25	0.01		2.320
June	2.14	-0.13	2.007	0.049563	0.25	0.01		2.317
July	2.14	-0.13	2.014	0.049736	0.25	0.01		2.324
August	2.15	-0.13	2.021	0.049909	0.25	0.01		2.331
September	2.15	-0.13	2.025	0.050008	0.25	0.01		2.335
October	2.18	-0.13	2.055	0.050749	0.25	0.01		2.366
November	2.32	-0.13	2.188	0.054033	0.25	0.01		2.502
December	2.46	-0.13	2.333	0.057614	0.25	0.01		2.651

"Look Date" 1-Dec-98

KCI Gas Commodity Cost

1999	Strip Price	Est Basis	WNG	Fuel	Transport	ACA/GRI	LDC	Burner Tip
January	1.99	-0.13	1.858	0.045884	0.25	0.01	0.15	2.314
February	2.02	-0.13	1.885	0.04655	0.25	0.01	0.15	2.342
March	2.01	-0.13	1.88	0.046427	0.25	0.01	0.15	2.336
April	2.00	-0.13	1.87	0.04618	0.25	0.01	0.15	2.326
May	2.02	-0.13	1.885	0.04655	0.25	0.01	0.15	2.342
June	2.02	-0.13	1.888	0.046624	0.25	0.01	0.15	2.345
July	2.03	-0.13	1.9	0.046921	0.25	0.01	0.15	2.357
August	2.04	-0.13	1.912	0.047217	0.25	0.01	0.15	2.369
September	2.06	-0.13	1.925	0.047538	0.25	0.01	0.15	2.383
October	2.11	-0.13	1.98	0.048896	0.25	0.01	0.15	2.439
November	2.25	-0.13	2.122	0.052403	0.25	0.01	0.15	2.584
December	2.40	-0.13	2.275	0.056181	0.25	0.01	0.15	2.741

2000	Strip Price	Est Basis	WNG	Fuel	Transport	ACA/GRI	LDC	Burner Tip
January	2.46	-0.13	2.335	0.057663	0.25	0.01	0.15	2.803
February	2.36	-0.13	2.23	0.055070	0.25	0.01	0.15	2.695
March	2.25	-0.13	2.12	0.052354	0.25	0.01	0.15	2.582
April	2.17	-0.13	2.04	0.050378	0.25	0.01	0.15	2.500
May	2.14	-0.13	2.01	0.049637	0.25	0.01	0.15	2.470
June	2.14	-0.13	2.007	0.049563	0.25	0.01	0.15	2.467
July	2.14	-0.13	2.014	0.049736	0.25	0.01	0.15	2.474
August	2.15	-0.13	2.021	0.049909	0.25	0.01	0.15	2.481
September	2.15	-0.13	2.025	0.050008	0.25	0.01	0.15	2.485
October	2.18	-0.13	2.055	0.050749	0.25	0.01	0.15	2.516
November	2.32	-0.13	2.188	0.054033	0.25	0.01	0.15	2.652
December	2.46	-0.13	2.333	0.057614	0.25	0.01	0.15	2.801

"Look Date" 1-Dec-98

Pleasant Hill Gas Commodity Cost

1999	Strip Price	Est Basis	WNG	Fuel	Transport	ACA/GRI	LDC	Burner Tip
January	1.99	-0.13	1.858	0.045884	0.05	0.01		1.964
February	2.02	-0.13	1.885	0.04655	0.05	0.01		1.992
March	2.01	-0.13	1.88	0.046427	0.05	0.01		1.986
April	2.00	-0.13	1.87	0.04618	0.05	0.01		1.976
May	2.02	-0.13	1.885	0.04655	0.05	0.01		1.992
June	2.02	-0.13	1.888	0.046624	0.05	0.01		1.995
July	2.03	-0.13	1.9	0.046921	0.05	0.01		2.007
August	2.04	-0.13	1.912	0.047217	0.05	0.01		2.019
September	2.06	-0.13	1.925	0.047538	0.05	0.01		2.033
October	2.11	-0.13	1.98	0.048896	0.05	0.01		2.089
November	2.25	-0.13	2.122	0.052403	0.05	0.01		2.234
December	2.40	-0.13	2.275	0.056181	0.05	0.01		2.391

2000	Strip Price	Est Basis	WNG	Fuel	Transport	ACA/GRI	LDC	Burner Tip
January	2.46	-0.13	2.335	0.057663	0.05	0.01		2.453
February	2.36	-0.13	2.23	0.055070	0.05	0.01		2.345
March	2.25	-0.13	2.12	0.052354	0.05	0.01		2.232
April	2.17	-0.13	2.04	0.050378	0.05	0.01		2.150
May	2.14	-0.13	2.01	0.049637	0.05	0.01		2.120
June	2.14	-0.13	2.007	0.049563	0.05	0.01		2.117
July	2.14	-0.13	2.014	0.049736	0.05	0.01		2.124
August	2.15	-0.13	2.021	0.049909	0.05	0.01		2.131
September	2.15	-0.13	2.025	0.050008	0.05	0.01		2.135
October	2.18	-0.13	2.055	0.050749	0.05	0.01		2.166
November	2.32	-0.13	2.188	0.054033	0.05	0.01		2.302
December	2.46	-0.13	2.333	0.057614	0.05	0.01		2.451

Firm Gas Reservation Cost

Merchant Energy Partners Proposal

	MMBtu Required			
	MW	Heat Rate	Hours/Day	MMBtu/day
April - Sept	500	7,041	24	84,492
Oct - March	200	7,356	24	35,309

	Annual Gas Reservation Cost			
	$/Dthrm/Mo	MMBtu/day	Months	Cost
April - Sept	$ 9.56	84,492	6	$4,846,461
Oct - March	$ 9.56	35,309	6	$2,025,313
Annual Cost				$6,871,774

Houston Industries Proposal

	MMBtu Required			
	MW	Heat Rate	Hours/Day	MMBtu/day
June - Sept	500	10,600	24	127,200
Oct - May	200	10,600	24	50,880

	Annual Gas Reservation Cost			
	$/Dthrm/Mo	MMBtu/day	Months	Cost
June - Sept	$ 9.56	127,200	4	$4,864,128
Oct - May	$ 9.56	50,880	8	$3,891,302
Annual Cost				$8,755,430

CASE 4 Gas Reservation Cost

Gas Usage - 350 MW

	MMBtu Required		
	Max Day	Max Mo.	Avg Mo.
April - Sept	59,500	1,920,000	1,511,000
Oct - March	35,000	1,000,000	910,000

	$/Dthrm/Mo.	
April - Sept	$ 9.56	$ 2,275,280
Oct - March	$ 9.56	$ 2,676,800
Annual Cost		$ 4,952,080

Missouri Power Supply
Bid Comparison
6/1/2001 - 5/31/2005
$x1,000

Without Off System Sales

	Jun-01	Jun-02	Jun-03	Jun-04	NPV Jun-01
From> / To>	May-02	May-03	May-04	May-05	May-05
2.5% Gas & Base Mkt					
Merchant Energy Partners	130,139	136,974	145,552	155,784	467,982
Houston Industries	129,268	136,062	146,002	156,282	467,117
1.0% Gas & Low Mkt					
Merchant Energy Partners	128,260	135,234	143,250	152,399	460,435
Houston Industries	127,253	133,600	142,937	152,552	457,966
4.0% Gas & High Mkt					
Merchant Energy Partners	131,883	138,309	147,493	158,665	474,546
Houston Industries	130,628	137,939	148,474	159,645	474,420
2.5% Gas & High Mkt					
Merchant Energy Partners	131,776	137,712	146,524	157,171	471,922
Houston Industries	130,664	137,748	147,939	158,619	473,111
2.5% Gas & Low Mkt					
Merchant Energy Partners	128,367	135,505	143,943	153,526	462,145
Houston Industries	127,291	133,780	143,329	152,976	458,778
2.5% Gas & No Mkt					
Merchant Energy Partners	139,103	141,427	149,751	160,010	486,539
Houston Industries	138,678	146,827	157,098	167,034	501,771
1.0% Gas & No Mkt					
Merchant Energy Partners	138,871	140,652	148,138	157,210	482,321
Houston Industries	138,496	146,133	155,469	164,100	497,558
4.0% Gas & No Mkt					
Merchant Energy Partners	139,332	142,222	151,320	162,818	490,742
Houston Industries	138,862	147,528	158,359	169,102	505,063

With Off System Sales

	Jun-01	Jun-02	Jun-03	Jun-04	NPV Jun-01
From> / To>	May-02	May-03	May-04	May-05	May-05
2.5% Gas & Base Mkt					
Merchant Energy Partners	120,645	129,426	139,021	149,469	442,894
Houston Industries	124,080	131,802	142,643	152,936	453,535
1.0% Gas & Low Mkt					
Merchant Energy Partners	121,758	130,149	138,758	147,996	443,252
Houston Industries	123,961	130,875	140,731	150,202	449,103
4.0% Gas & High Mkt					
Merchant Energy Partners	118,753	127,684	138,396	150,342	439,794
Houston Industries	122,910	131,846	143,694	155,201	454,988
2.5% Gas & High Mkt					
Merchant Energy Partners	118,229	126,818	136,691	147,955	435,458
Houston Industries	123,962	130,754	141,296	150,808	449,893
2.5% Gas & Low Mkt					
Merchant Energy Partners	121,984	130,778	139,942	149,787	446,258
Houston Industries	124,051	131,191	141,367	150,981	450,535

Revised: March 1, 1999

Merchant Energy Partners Contract
Annual Ownership and Operating Cost
$x1,000

From>	Jun-01	Jun-02	Jun-03	Jun-04
To>	May-02	May-03	May-04	May-05
Aquila Capacity Payment				
MEP Capacity Payment	17,696	27,660	27,660	27,660
SEC Capacity Payment	6,693			
Union Electric Capacity Payment				
Long Term Peaking Capacity Cost				
Short Term Peaking Capacity Cost			2,837	6,397
Gas Reservation Cost	6,872	6,872	6,872	6,872
Total Fixed Costs	31,261	34,532	37,368	40,929
Without Off System Sales				
MWh $ w/ 2.5% Gas & Base Mkt	98,878	102,442	108,184	114,856
Total Cost	130,139	136,974	145,552	155,784
MWh $ w/ 1.0% Gas & Low Mkt	96,999	100,702	105,882	111,470
Total Cost	128,260	135,234	143,250	152,399
MWh $ w/ 4.0% Gas & High Mkt	100,622	103,777	110,124	117,936
Total Cost	131,883	138,309	147,493	158,865
MWh $ w/ 2.5% Gas & High Mkt	100,516	103,180	109,156	116,243
Total Cost	131,776	137,712	146,524	157,171
MWh $ w/ 2.5% Gas & Low Mkt	97,106	100,973	106,574	112,598
Total Cost	128,367	135,505	143,943	153,526
MWh $ w/ 2.5% Gas & No Mkt	107,842	106,895	112,383	119,082
Total Cost	139,103	141,427	149,751	160,010
MWh $ w/ 1.0% Gas & No Mkt	107,610	106,120	110,770	116,281
Total Cost	138,871	140,652	148,138	157,210
MWh $ w/ 4.0% Gas & No Mkt	108,071	107,691	113,952	121,889
Total Cost	139,332	142,222	151,320	162,818
With Off System Sales				
MWh $ w/ 2.5% Gas & Mkt	89,384	94,895	101,653	108,541
Total Cost	120,645	129,426	139,021	149,469
MWh $ w/ 1.0% Gas & Mkt	90,497	95,617	101,390	107,067
Total Cost	121,758	130,149	138,758	147,996
MWh $ w/ 4.0% Gas & Mkt	87,492	93,153	101,027	109,414
Total Cost	118,753	127,684	138,396	150,342
MWh $ w/ 2.5% Gas & High Mkt	86,968	92,286	99,323	107,026
Total Cost	118,229	126,818	136,691	147,955
MWh $ w/ 2.5% Gas & Low Mkt	90,723	96,246	102,574	108,859
Total Cost	121,984	130,778	139,942	149,787

Revise: March 1, 1999

Houston Industries Contract
Annual Ownership and Operating Cost
$x1,000

From>	Jun-01	Jun-02	Jun-03	Jun-04
To>	May-02	May-03	May-04	May-05
Houston Capacity Payment	23,576	23,576	23,576	23,576
Aquila Capacity Payment				
SEC Capacity Payment				
Union Electric Capacity Payment				
Long Term Peaking Capacity Cost				
Short Term Peaking Capacity Cost			2,837	6,397
Gas Reservation Cost	8,755	8,755	8,755	8,755
Total Fixed Costs	32,331	32,331	35,168	38,728
<u>Without Off System Sales</u>				
MWh $ w/ 2.5% Gas & Base Mkt	96,937	103,731	110,834	117,554
Total Cost	129,268	136,062	146,002	156,282
MWh $ w/ 1.0% Gas & Low Mkt	94,922	101,268	107,769	113,824
Total Cost	127,253	133,600	142,937	152,552
MWh $ w/ 4.0% Gas & Low Mkt	98,296	105,608	113,306	120,917
Total Cost	130,628	137,939	148,474	159,645
MWh $ w/ 2.5% Gas & High Mkt	98,333	105,417	112,771	119,891
Total Cost	130,664	137,748	147,939	158,619
MWh $ w/ 2.5% Gas & Low Mkt	94,960	101,449	108,161	114,248
Total Cost	127,291	133,780	143,329	152,976
MWh $ w/ 2.5% Gas & No Mkt	106,347	114,496	121,930	128,306
Total Cost	138,678	146,827	157,098	167,034
MWh $ w/ 1.0% Gas & No Mkt	106,165	113,801	120,301	125,372
Total Cost	138,496	146,133	155,469	164,100
MWh $ w/ 4.0% Gas & No Mkt	106,530	115,197	123,191	130,374
Total Cost	138,862	147,528	158,359	169,102
<u>With Off System Sales</u>				
MWh $ w/ 2.5% Gas & Base Mkt	91,748	99,470	107,475	114,208
Total Cost	124,080	131,802	142,643	152,936
MWh $ w/ 1.0% Gas & Low Mkt	91,630	98,544	105,563	111,474
Total Cost	123,961	130,875	140,731	150,202
MWh $ w/ 4.0% Gas & Low Mkt	90,579	99,514	108,525	116,473
Total Cost	122,910	131,846	143,694	155,201
MWh $ w/ 2.5% Gas & High Mkt	91,630	98,423	106,128	112,079
Total Cost	123,962	130,754	141,296	150,808
MWh $ w/ 2.5% Gas & Low Mkt	91,720	98,859	106,199	112,253
Total Cost	124,051	131,191	141,367	150,981

CASE 4
Annual Ownership and Operating Cost
$x1,000

From>	Jun-01	Jun-02	Jun-03	Jun-04	NPV Jun-01
To>	May-02	May-03	May-04	May-05	May-05
Aquila Capacity Payment					
CP&L Capacity Payment	9,957	10,205	10,454	10,454	
NP Energy Capacity Payment	5,100	5,228	5,358	5,492	
SCEM Capacity Payment	5,576	5,680	5,786	5,897	
SPS Capacity Payment	11,968	12,227	12,227	12,227	
Union Electric Capacity Payment					
Long Term Peaking Capacity Cost				9,479	
Short Term Peaking Capacity Cost		2,214	5,673	582	
Gas Reservation Cost	4,952	4,952	4,952	7,074	
Total Fixed Costs	37,553	40,505	44,451	51,204	
Without Off System Sales					
MWh $ w/Base Gas & Mkt	106,844	112,586	118,605	120,584	
Total Cost	144,397	153,091	163,055	171,788	520,660
MWh $ w/Low Gas & Mkt	105,802	110,791	116,112	116,197	
Total Cost	143,355	151,297	160,562	167,401	512,953
MWh $ w/ High Gas & Mkt	107,848	114,088	120,889	124,837	
Total Cost	145,401	154,593	165,340	176,041	527,817
With Off System Sales					
MWh $ w/Base Gas & Mkt	97,261	103,856	110,773	120,012	
Total Cost	134,814	144,361	155,224	171,216	497,665
MWh $ w/Low Gas & Mkt	99,533	105,103	110,875	115,996	
Total Cost	137,086	145,609	155,326	167,200	497,967
MWh $ w/ High Gas & Mkt	94,034	101,772	109,574	123,976	
Total Cost	131,587	142,277	154,024	175,180	494,851

UTILICORP UNITED INC.

MISSOURI PUBLIC SERVICE

1999-2004
ENERGY SUPPLY PLAN

MARCH 19, 1999
UPDATE

Table of Contents

1. EXECUTIVE SUMMARY

On August 24, 1998, Missouri Public Service (MPS) presented its Preliminary Energy Supply Plan for 1998 - 2003. At that time, the recommended action plan consisted of the following three steps:

- Negotiate extensions of the existing lease agreements on the Nevada and Greenwood combustion turbines;
- Secure short term capacity to meet MPS' capacity needs through 2000; and,
- Pursue the construction of a 500 MW combined cycle unit with an in service date of June 1, 2001.

Since the presentation of its Preliminary Action Plan last August, MPS has pursued all three elements of its action plan with the following results:

- Successfully negotiated the purchase of the Nevada combustion turbine from the lease holder for $1.6 million ($80.00/kw).
- Executed a purchase power contract for 135 MW of short term peaking capacity contract with Aquila Energy Marketing Corporation (AEMC) for the year 2000 summer season. This contract has been filed with the Federal Energy Regulatory Commission (FERC) for its approval.
- Secured a flexible option to purchase additional peaking capacity for the summer seasons of 2000 and 2001. The flexibility of the option will enable MPS to optimize its purchase of capacity to meet a range of capacity needs in both years. This contract has not yet been executed.
- Executed a contract with MEP Pleasant Hill, LLC (MEP) for the purchase of up to 500 MW of intermediate capacity for the period from June, 2001 to May, 2005. This contract has been filed with the Missouri Public Service Commission (MPSC) for its approval. Upon approval of the contract by the MPSC, the contract will be submitted to the FERC for its approval.

In addition, MPS has budgeted and is pursuing the capacity enhancements to its existing fleet of generating units that were presented in the Preliminary Energy Supply Plan. A review of these enhancements and the projected completion date for each one is discussed in Section 2.3.

The remainder of this update will focus on the following areas:

- Load & Resource Forecast
- Generation Resources
- Purchase Power Resources

2. LOAD & RESOUCE FORECAST

MPS updated its base, pessimistic and optimistic load forecasts earlier this year. As a result, revised load & resources forecasts for each load forecast have been prepared. The projected loads & resources forecasts are shown in Table 2.1, 2.2, and 2.3 for the respective load forecasts.

The two purchase power contracts, the purchase option and the capacity enhancements listed in the executive summary are all included in the projected energy supply portfolio. Note that the capacity option allows MPS to match its capacity purchase to the forecast capacity needs under each of the three load forecast scenarios for the years 2000 and 2001.

Table 2.1: Load & Resources Forecast for Base Load Forecast

Forecast Year	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Projected Firm Load	1,197	1,202	1,229	1,258	1,286	1,320	1,350	1,385	1,419	1,445	1,472
Load Responsibility	1,197	1,202	1,229	1,258	1,286	1,320	1,350	1,385	1,419	1,445	1,472
Capacity Reserves @ 12%	163	164	168	172	175	180	184	189	194	197	201
Total Capacity Requirement	1,360	1,366	1,397	1,430	1,461	1,499	1,534	1,574	1,613	1,643	1,673
Generation Resources											
Sibley #1	54	54	54	54	54	54	54	54	54	54	54
Sibley #2	54	54	54	54	54	54	54	54	54	54	54
Sibley #3	395	395	395	410	410	410	410	410	410	410	410
JEC #1	57	57	57	57	57	57	57	57	57	57	57
JEC #2	57	57	57	57	57	57	57	57	57	57	57
JEC #3	58	58	58	58	58	58	58	58	58	58	58
RG #3	74	74	74	74	74	74	74	74	74	74	74
GW #1	62	62	67	67	67	67	67	67	67	67	67
GW #2	62	62	67	67	67	67	67	67	67	67	67
GW #3	62	62	67	67	67	67	67	67	67	67	67
GW #4	61	61	67	67	67	67	67	67	67	67	67
Nevada	20	20	20	20	20	20	20	20	20	20	20
KCI #1	15	15	18	18	18	18	18	18	18	18	18
KCI #2	18	18	18	18	18	18	18	18	18	18	18
Total Generation	1,047	1,047	1,070	1,085	1,085	1,085	1,085	1,085	1,085	1,085	1,085
Capacity Purchases											
AECI	160	190									
KCPL	60	90									
UE	115										
OPTION			95	25							
AEMC			135								
MEP				320	500	500	500				
1999 RFP		50	100								
Total Purchase	335	330	330	345	500	500	500	0	0	0	0
Total Generation + Capacity Purchase	1,382	1,377	1,400	1,430	1,585	1,585	1,585	1,085	1,085	1,085	1,085
Net Capacity Balance	22	11	3	1	124	86	51	(489)	(527)	(557)	(588)

Table 2.2: Load & Resources Forecast for Optimistic Load Forecast

Forecast Year	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Projected Firm Load	1,197	1,209	1,243	1,279	1,315	1,357	1,396	1,441	1,484	1,523	1,561
Load Responsibility	1,197	1,209	1,243	1,279	1,315	1,357	1,396	1,441	1,484	1,523	1,561
Capacity Reserves @ 12%	163	165	170	174	179	185	190	197	202	208	213
Total Capacity Requirement	1,360	1,374	1,413	1,453	1,494	1,542	1,587	1,638	1,687	1,731	1,774
Generation Resources											
Sibley #1	54	54	54	54	54	54	54	54	54	54	54
Sibley #2	54	54	54	54	54	54	54	54	54	54	54
Sibley #3	395	395	395	410	410	410	410	410	410	410	410
JEC #1	57	57	57	57	57	57	57	57	57	57	57
JEC #2	57	57	57	57	57	57	57	57	57	57	57
JEC #3	58	58	58	58	58	58	58	58	58	58	58
RG #3	74	74	74	74	74	74	74	74	74	74	74
GW #1	62	62	67	67	67	67	67	67	67	67	67
GW #2	62	62	67	67	67	67	67	67	67	67	67
GW #3	62	62	67	67	67	67	67	67	67	67	67
GW #4	61	61	67	67	67	67	67	67	67	67	67
Nevada	20	20	20	20	20	20	20	20	20	20	20
KCI #1	15	15	18	18	18	18	18	18	18	18	18
KCI #2	18	18	18	18	18	18	18	18	18	18	18
Total Generation	1,047	1,047	1,070	1,085	1,085	1,085	1,085	1,085	1,085	1,085	1,085
Capacity Purchases											
AECI	160	190									
KCPL	60	90									
UE	115										
OPTION			110	50							
AEMC			135								
MEP				320	500	500	500				
1999 RFP		50	100								
Total Purchase	335	330	345	370	500	500	500	0	0	0	0
Total Generation + Capacity Purchase	1,382	1,377	1,415	1,455	1,585	1,585	1,585	1,085	1,085	1,085	1,085
Net Capacity Balance	22	3	2	2	91	43	(1)	(552)	(601)	(645)	(689)

Table 2.3: Load & Resources Forecast for Pessimistic Load Forecast

Forecast Year	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
Projected Firm Load	1,197	1,195	1,217	1,239	1,259	1,286	1,307	1,335	1,359	1,375	1,390
Load Responsibility	1,197	1,195	1,217	1,239	1,259	1,286	1,307	1,335	1,359	1,375	1,390
Capacity Reserves @ 12%	163	163	166	169	172	175	178	182	185	188	190
Total Capacity Requirement	1,360	1,358	1,383	1,408	1,431	1,461	1,485	1,517	1,545	1,563	1,580
Generation Resources											
Sibley #1	54	54	54	54	54	54	54	54	54	54	54
Sibley #2	54	54	54	54	54	54	54	54	54	54	54
Sibley #3	395	395	395	410	410	410	410	410	410	410	410
JEC #1	57	57	57	57	57	57	57	57	57	57	57
JEC #2	57	57	57	57	57	57	57	57	57	57	57
JEC #3	58	58	58	58	58	58	58	58	58	58	58
RG #3	74	74	74	74	74	74	74	74	74	74	74
GW #1	62	62	67	67	67	67	67	67	67	67	67
GW #2	62	62	67	67	67	67	67	67	67	67	67
GW #3	62	62	67	67	67	67	67	67	67	67	67
GW #4	61	61	67	67	67	67	67	67	67	67	67
Nevada	20	20	20	20	20	20	20	20	20	20	20
KCI #1	15	15	18	18	18	18	18	18	18	18	18
KCI #2	18	18	18	18	18	18	18	18	18	18	18
Total Generation	1,047	1,047	1,070	1,085	1,085	1,085	1,085	1,085	1,085	1,085	1,085
Capacity Purchases											
AECI	160	190									
KCPL	60	90									
UE	115										
OPTION			80	5							
AEMC			135								
MEP				320	500	500	500				
1999 RFP		50	100								
Total Purchase	335	330	315	325	500	500	500	0	0	0	0
Total Generation + Capacity Purchase	1,382	1,377	1,385	1,410	1,585	1,585	1,585	1,085	1,085	1,085	1,085
Net Capacity Balance	22	18	2	3	155	124	100	(431)	(459)	(478)	(494)

3. GENERATION RESOURCES

3.1 Overview

During 1998, UtiliCorp's Missouri Public Service (MPS) electric supply portfolio consisted of fourteen generating units with an accredited capacity of 1,047 MW and three purchase power contracts representing a total purchase capacity of 345 MW. Actual system coincident peak load was 1,197 MW in July. Actual system load factor was 47%, based on net energy for load of 4,657,936 MWh dispatched. The MPS capacity mix was 36% peaking capacity and 64% base load capacity. MPS' single largest generating unit is the coal-fired Sibley Unit 3, which has a net rated capacity of 395 MW. MPS' other coal-fired resources include its 171 MW ownership in the Jeffery Energy Center and 107 MW in Sibley units #1 & #2.. MPS also owns 127 MW of peaking capacity and leases an additional 247 MW of peaking capacity.

Due to the increasing shortage of generating capacity and the associated price escalation for existing surplus and/or new capacity resources, MPS plans to continue to operate and maintain its present fleet of generating assets through the first decade of the next century.

3.2 1999 Maintenance Plan:

At the Sibley Station, turbine overhauls are scheduled to be performed on Units #1 & #2. Siemens Westinghouse has been contracted to manage the turbine overhauls for both units.

Overhaul work on Sibley Unit #2 has been completed with needed repairs made in the following areas: diaphragms, blade erosion, bearing clearances, alignment, etc. In addition to the turbine work, new condenser tubes were installed and other routine boiler maintenance performed. General Electric provided engineering support for the project.

The turbine overhaul for Sibley Unit #1 is currently in progress. This work will be routine in nature as the steam turbine internal parts were refurbished during previous overhauls.

A routine spring maintenance outage will be performed on Sibley Unit #3 (currently scheduled for the period April 10th - 30th)following the turbine overhauls on units #1 & #2. Work will focus on routine boiler repairs in the burner area. In addition, NOx reduction equipment will be installed and minor turbine valve work performed.

JEC #1 spring outage is currently in progress and will be completed by the end of March. During the outage, the economizer section of the boiler was replaced. New combustion controls and turbine controls were also installed.

The spring outage for JEC #2 will begin at the end of March and will be completed in early May. During the outage the economizer section of the boiler, the air heater baskets and the turbine controls will be replaced. The combustion controls will also be upraded.

The sping outage for JEC #3 will begin at the end of the JEC #2 outage and will last one week. Only routine maintenance will be performed.

Routine maintenance will be performed on all combustion turbine units. In addition to routine maintenance, a combustor inspection was completed on GW #3 and a fuel nozzle and combustor liner inspection was completed on RG #3.

3.3 Power Plant Improvements

The following specific equipment modifications to existing MPS generating resources have been identified and included in its supply plan.

A. New High Flow Inlet Guide Vanes - Greenwood (8 MW)
Combustion turbine inlet guide vanes (IGVs) act as air flow dampers during startup and low load operation. This necessary feature for low load operation can penalize full load output by restricting inlet air flow. IGVs are an item typically requiring replacement due to fatigue. Using new alloys, thinner IGVs can replace the originals and provide greater air flow at high output and with it higher capacity. These modifications have the advantages of not impacting O&M, emissions rates, or operating procedures. This upgrade will be completed prior to the summer peak in 2000.

B. Water Injection - Greenwood (12 MW)
The capacity of a combustion turbine is directly proportional to the mass flow through the turbine. Water can be injected at the turbine inlet through the fuel nozzle to increase the mass flow. The advantages of this modification are that it lowers NOx, is easily dispatched, and has industry acceptance. Disadvantages are the delivery, handling, storage and processing of the water, and water injection has a negative impact on the turbines heat rate. This upgrade will be completed prior to the summer peak in 2000.

C. Upgrade Jet Engines - KCI Airport (4 MW)
The jet engines at Kansas City International (KCI) Airport are late 1960s vintage. The manufacturer made improvements to these engines throughout the 1970s. In general, the capacity of these units is limited by the firing temperature. Replacing the units' blades and vanes with higher temperature components will allow the units to operate at higher temperatures. The advantage of these modifications include no impacts to O&M, operating

procedures, or emissions rates. This upgrade will be completed prior to the summer peak in 2000.

D. Boiler/Turbine Upgrade - Sibley (15 MW)
The turbine manufacturer, Westinghouse, and the boiler manufacturer, Babcock & Wilcox, have indicated that additional capacity is available through modifications to the steam turbine and boiler, including some plant auxiliaries. This upgrade is planned for 2000/2001 with the increased capacity available for the 2001 peak season.

3.4 Combustion Turbine Lease Renewal

MPS currently leases the four Greenwood combustion turbines.

Prior to this year, MPS also leased the Nevada combustion turbine. Using the action plan outlined below, MPS negotiated with the current lease holder who no longer wished to own the unit and was able to purchase the unit for $1.5 million plus overheads.

The following table shows the unit, capacity and current lease termination date for the Greenwood units.

Table 3.4-1 Leased Combustion Turbine Data

Unit Name	Capacity (MW)	Lease Termination
Greenwood #1	62	June, 2000
Greenwood #2	62	June, 2000
Greenwood #3	62	June, 2002
Greenwood #4	61	June, 2004

MPS is pursuing the following plan of action to determine whether it should renew the leases, terminate the leases or purchase the units.

- Determine the market value of the units to the lease holders.
- Determine the value of the capacity to MPS.
- Develop Renegotiation Strategy

The above process has revealed a gap between the value of the units to the lease holders and the value to MPS with the value to MPS being approximately twice the market value of the units to the lease holders. Using this information, a strategy was developed in which MPS will offer the following options to the lease holders:

1) Purchase the units at a price that is equivalent to the NPV of the five year lease payments; or,
2) Lease the units for five years for a lease payment stream which will have the same NPV as the unit's fair market value.

Based on its analysis of the inability of simple cycle combustion turbine technology to compete in a deregulated marketplace and the age of the leased units, option 2 is the preferred option. The following table shows the time line for completion of the action plan.

Table 3.4-2: Timetable for CT Lease Renewal/Purchase

Activity	Date
Complete Market Value Study	June 15, 1998
Complete Lease/Buy Analysis	June 30, 1998
Complete Nevada Negotiations	December 1, 1998
Complete GEC 1 & 2 Negotiations	December 1, 1999
Complete GEC 3 Negotiations	December 1, 2001
Complete GEC 4 Negotiations	December 1, 2003

4. PURCHASED POWER RESOURCES

MPS currently purchases capacity and energy through purchase power contracts with two neighboring utilities.

The first contract is with Associated Electric Cooperative (AEC). Capacity and energy are purchased under an agreement executed in 1987, and amended in 1988, 1989 and 1994. The AEC purchase contract expires on May 31, 2000, at which time the contract capacity amount totals 190 MW.

The second contract is with Kansas City Power and Light (KCPL). Capacity and energy are purchased under an agreement executed in 1997. The KCPL contract expires on September 30, 1999, at which time the contract capacity amount totals 90 MW.

MPS also had a contract with Union Electric (UE) to purchase 115 MW of capacity and energy. That agreement was terminated on February 28 of this year. MPS is currently evaluating proposals to replace the capacity and expects to execute a contract by the end of March. The "Unmet Need" shown for 1999 & 2000 in Table 4.1 reflect the shortfall created by the termination of the UE contract.

In addition to the above contracts, MPS has executed two additional contracts to supply capacity and energy beginning in 2000. The first contract is with Aquila Energy Marketing Corporation (AEMC) which will provide 135 MW of peaking capacity and energy in the summer of 2000. The second contract is with MEP Pleasant Hill, LLC (MEP) which will provide 320 MW of peaking capacity in 2001 and 500 MW of intermediate capacity and energy in the years 2002 - 2004.

Finally, MPS has an option to purchase peaking capacity and energy from a regional utility in 2000 & 2001. The purchase amount is flexible and will be adjusted to meet MPS' capacity needs.

The following table summarizes the external power supply arrangements discussed above as well as the current unmet capacity needs of MPS.

Table 4-1: MPS Purchase Power Contracts

Year (June 1)	UE Contract (MW)	AEC Contract (MW)	KCPL Contract (MW)	Option Resource (MW)	AEMC Contract (MW)	MEP Contract (MW)	Total (MW)	Unmet Need (MW)
1998	115	170	60				345	
1999		190	90				280	50
2000				80/110	135		215/245	100
2001				5/50		320	325/370	
2002						500	500	
2003						500	500	
2004						500	500	

RECEIPT COPY

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

FILED

MAR - 1 1999

Missouri Public
Service Commission

RECEIVED
MAR - 1 1999
OFFICE OF THE PUBLIC COUNSEL

In the Matter of the Application of UtiliCorp United Inc. under §32(k) of the Public Utilities Holding Company Act of 1935 Concerning a Proposed Power Sales Agreement Between MEP Pleasant Hill, L.L.C. and UtiliCorp United Inc. d/b/a Missouri Public Service.	)	Case No. EM-99-369

APPLICATION

COMES NOW UtiliCorp United Inc. ("UtiliCorp"), d/b/a Missouri Public Service ("MPS"), pursuant to §32(k) of the Public Utility Holding Company Act of 1935 ("PUHCA"), 4 CSR 240-2.060(1) and 4 CSR 240-2.080 and in support of its Application to the Missouri Public Service Commission ("Commission") for an order with respect to a Power Sales Agreement ("PSA") between UtiliCorp and MEP Pleasant Hill, L.L.C. ("MEPPH"), states as follows:

1. UtiliCorp is a Delaware corporation, in good standing in all respects, with its principal office and place of business at 20 West Ninth, Kansas City, Missouri 64105. UtiliCorp is authorized to conduct business in Missouri through its MPS operating division and, as such, is engaged in providing electrical and natural gas utility service in its service areas subject to the jurisdiction of this Commission as provided by law. UtiliCorp's Certificate of Incorporation and Amended Certificate of Authority of a Foreign Corporation have been filed in Commission Case No. EM-87-6 and said documents are incorporated herein by reference, collectively, as <u>Appendix 1</u> hereto, and made a part hereof for all purposes.

2. MEPPH is a limited liability company organized under and by virtue of the laws of the State of Delaware, in good standing in all respects, with its principal office and place of business at

10750 350 Highway, Kansas City, Missouri 64138. A certified copy of MEPPH's Certificate of Registration to transact business in the State of Missouri is attached hereto as Appendix 2, and made a part hereof for all purposes. MEPPH is a subsidiary of UtiliCorp.

3. All communications, notices, orders and decisions with respect to this Application and proceeding should be addressed to:

Gary Clemens
Manager Regulatory Services
UtiliCorp United Inc.
10700 E. 350 Highway
Kansas City, MO 64138
(816) 936-8634

James C. Swearengen
Paul A. Boudreau
Brydon, Swearengen & England P.C.
312 E. Capitol Avenue
P.O. Box 456
Jefferson City, MO 65102-0456
(573) 635-7166

4. In connection with its Missouri jurisdictional electrical operations which it conducts through MPS, UtiliCorp has entered into certain contracts pursuant to which it purchases wholesale electric power. Specifically, UtiliCorp has contracted with Union Electric Company (now AmerenUE) for 115 megawatts of capacity and with Associated Electric Cooperative for 190 megawatts of capacity. In addition, UtiliCorp has contracted with Kansas City Power & Light Company for 90 megawatts of capacity. These contracts, which collectively represent 395 megawatts of capacity, will, by their terms, expire over a period of the next 26 months.

5. Accordingly, UtiliCorp will be required to have in place other capacity to meet its projected needs by the year 2000. To accomplish this, UtiliCorp has entered into a competitive

bidding process pursuant to which it issued a Request for Proposal ("RFP") on May 22, 1998, for both annual and seasonal purchased power capacity. A copy of the RFP is attached hereto as Appendix 3 and made a part hereof for all purposes. This RFP was forwarded to Staff and the Office of the Public Counsel ("OPC") for comment under integrated resource plan ("IRP") format on August 24, 1998.

6. The eight (8) proposals received in response to the RFP were opened on July 6, 1998, and were thereafter subjected to an internal review and evaluation by UtiliCorp and an independent third-party review and evaluation by the engineering consulting firm of Burns & McDonnell. These proposals were also forwarded to Staff and OPC under the IRP on August 24, 1998. The reviews and evaluations were provided to Staff and OPC on February 8, 1999. The objective of these evaluations was to determine the power supply option, or combination of options, which, when combined with UtiliCorp's existing resources, would result in the lowest total cost of power supply during the period of June 1, 2001, to May 31, 2005.

7. UtiliCorp has determined the successful (i.e., lowest cost) proposal to be the bid submitted by MEPPH. Accordingly, UtiliCorp has negotiated with MEPPH the terms of a PSA which will provide for 320 to 500 megawatts of capacity over a four (4) year term commencing June 1, 2001. Copies of the PSA, and an executive summary thereof, are attached hereto as Appendix 4 and Appendix 5, respectively, and made a part hereof for all purposes.

8. In order to protect against abusive affiliate transactions, subsection 32(k) of the PUHCA prohibits an electric utility, such as UtiliCorp, from entering into a purchase power agreement with an affiliated EWG unless every state commission having jurisdiction over the retail rates of the electric utility makes certain specific determination with respect to the agreement. Thus, it will be

necessary for the Commission to determine that it has sufficient regulatory authority, resources and access to books and records of UtiliCorp and any relevant affiliate or subsidiary such that it may exercise its duties under subsection 32(k) to determine that the proposed PSA (1) will benefit consumers; (2) does not violate any applicable state law (including, where applicable, least cost planning); (3) would not provide MEPPH any unfair competitive advantage by virtue of its affiliation with UtiliCorp; and (4) is in the public interest.[1] The PUHCA requires that the Commission make these findings with respect to the PSA before MEPPH may apply to the FERC for approval of the PSA. In fact, the Commission's order is a necessary exhibit to any application filed with the FERC.

9. Once Commission approval is obtained, MEPPH will file with the FERC a request for certification as an exempt wholesale generator ("EWG") and a request for approval of the PSA under applicable provisions of the PUHCA and the Federal Power Act. Shortly after obtaining such FERC approvals, MEPPH will commence with the construction of a 500 MW combined cycle combustion turbine generation plant in Cass County, Missouri, near the town of Pleasant Hill (the "Project") which Project will be operated by MEPPH to meet its contractual obligations under the PSA. MEPPH is not and will not be an "electrical corporation" as that term is defined at §386.020(15), RSMo 1998, inasmuch as it will sell electric power exclusively at wholesale and, thus, will not be engaged in the sale of electric power at retail to the general public. *See, State ex rel. M.O. Danciger v. Public Service Commission*, 205 S.W. 36 (Mo. 1918). MEPPH will be regulated by the FERC with respect to wholesale energy rates.

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[1]*See,* 15 U.S.C. §79z-5a(k).

10. A certified copy of the Resolutions of UtiliCorp's Board of Directors authorizing the PSA with MEPPH and the filing of this Application is attached hereto as Appendix 6, and made a part hereof for all purposes.

11. The Commission has broad statutory authority over the determination of retail rates by electrical corporations, including UtiliCorp, pursuant to Chapters 386 and 393, RSMo. The Commission's existing rules and regulations permit it to examine the books and records of UtiliCorp. Furthermore, the Commission, its Staff and the Office of the Public Counsel may examine the books, accounts, contracts and records of MEPPH as required for the effective discharge of the Commission's regulatory responsibilities affecting the provision of electric service by MPS. In addition, the Commission has a large staff of professional accountants, engineers, economists, attorneys, financial analysts and management specialists to advise it in this regard. Thus, the Commission has both the authority and resources to make the determinations required by the PUHCA as set forth in paragraph 8.

12. The PSA will ensure a steady, affordable and reliable source of electric power for distribution by MPS to its electric utility customers. Without the capacity which will be provided under the terms of the PSA, UtiliCorp will be unable to meet its projected capacity needs beginning in the year 2001. Therefore, it is essential that the projected energy needs of MPS customers are adequately and securely provided for.

13. The PSA does not violate any applicable state law and, without limitation, it does not conflict, in any way, with UtiliCorp's IRP obligations. UtiliCorp's RFP has complied in all respects with its IRP protocol.

14. The PSA will not provide MEPPH with any unfair competitive advantage by virtue of

its affiliation with UtiliCorp. As explained above, MEPPH's successful bid was the result of an arms' length competitive bidding process and MEPPH was supplied with no more information and granted no greater accommodation than was provided to any other respondent to the RFP. The eight (8) bids received were thoroughly examined not only by UtiliCorp but by an independent third party. Finally, the terms of the PSA are the result of an extensive arms' length negotiation between representatives of MEPPH and UtiliCorp each of which were represented and advised by separate counsel.

15. UtiliCorp understands that an order containing the findings required by the PUHCA with respect to the PSA shall in no way be binding on the Commission or any party to a future rate case to contest the ratemaking treatment to be afforded the PSA.

16. For the reasons aforesaid, the terms of the PSA are in the public interest.

17. It is imperative that MEPPH commence by the end of July of 1999 with the construction of the involved combustion turbine generation plant which will be located near Pleasant Hill, Missouri. The inability to obtain the necessary State and Federal regulatory approvals quickly may significantly impede UtiliCorp's ability to have in place the necessary capacity by the year 2001. Accordingly, UtiliCorp respectfully requests that the Commission issue an order approving this Application by May 1, 1999.

WHEREFORE, UtiliCorp respectfully requests that the Commission issue an order, no later than May 1, 1999: (A) specifically determining that the Commission has sufficient regulatory authority, resources and access to books and records of UtiliCorp and MEPPH to exercise its duties under subsection 32(k) of PUHCA to ensure that the proposed PSA (i) benefits consumers, (ii) does not violate any state law, (iii) does not provide MEPPH with any unfair competitive advantage by virtue of its affiliation with UtiliCorp and (iv) is in the public interest; (B) authorizing UtiliCorp to enter into, execute and perform in accordance with the terms and conditions of the proposed Power Service Agreement by and between MEPPH and UtiliCorp; (C) authorizing UtiliCorp to enter into, execute and perform in accordance with the terms of all documents reasonably necessary and incidental to the performance of the transactions which are the subject of this Application; and (D) granting such other authority as may be just and proper under the circumstances.

Respectfully submitted,

James C. Swearengen #21510
Paul A. Boudreau #33155
BRYDON, SWEARENGEN & ENGLAND P.C.
P.O. Box 456
Jefferson City, MO 65102-0456
(573) 635-7166

Attorneys for UtiliCorp United Inc., d/b/a Missouri Public Service

STATE OF MISSOURI)
) SS
COUNTY OF JACKSON)

I, John W. McKinney, of lawful age, being first duly sworn upon my oath, state that I am the Vice President-Regulatory Services of UtiliCorp United Inc.; that I am authorized to execute this document on behalf of UtiliCorp United Inc.; and that the facts set forth in the foregoing are true to the best of my knowledge, information and belief.

John W. McKinney

Subscribed and sworn to before me this 10th day of February, 1999.

Patricia A. Austin
Notary Public

My Commission Expires:
PATRICIA A. AUSTIN
Notary Public - State of Missouri
Commissioned in Jackson County
My Commission Expires: Dec. 12, 1999

(SEAL)

SCHEDULE FAD-24
Page 8 of 26

Certificate of Service

I hereby certify that a true and correct copy of the above and foregoing document was sent by U.S. Mail, postage prepaid, or hand-delivered, on this 1st day of March, 1999, to:

The Office of the Public Counsel
Truman Building, Room 250
P.O. Box 7800
Jefferson City, MO 65102-7800

APPENDIX 1

INCORPORATED BY REFERENCE

STATE OF MISSOURI

Rebecca McDowell Cook
Secretary of State

CORPORATION DIVISION

CERTIFICATE OF CORPORATE RECORDS

MEP PLEASANT HILL, LLC

I, REBECCA MCDOWELL COOK, SECRETARY OF STATE OF THE STATE OF MISSOURI AND KEEPER OF THE GREAT SEAL THEREOF, DO HEREBY CERTIFY THAT THE ANNEXED PAGES CONTAIN A FULL, TRUE AND COMPLETE COPY OF THE ORIGINAL DOCUMENTS ON FILE AND OF RECORD IN THIS OFFICE.

IN TESTIMONY WHEREOF, I HAVE SET MY HAND AND IMPRINTED THE GREAT SEAL OF THE STATE OF MISSOURI, ON THIS, THE 23RD DAY OF FEBRUARY, 1999.

Rebecca McDowell Cook

Secretary of State

STATE OF MISSOURI

SEAL OF THE SECRETARY OF STATE
MISSOURI

Rebecca McDowell Cook
Secretary of State

CERTIFICATE OF REGISTRATION
FOREIGN LIMITED LIABILITY COMPANY

WHEREAS,
MEP PLEASANT HILL, LLC

USING IN MISSOURI THE NAME
MEP PLEASANT HILL, LLC

AND EXISTING UNDER THE LAWS OF THE STATE OF DELAWARE HAS FILED WITH THIS STATE ITS APPLICATION FOR REGISTRATION AND WHEREAS THIS APPLICATION FOR REGISTRATION CONFORMS TO THE MISSOURI LIMITED LIABILITY COMPANY ACT;

NOW, THEREFORE, I, REBECCA MCDOWELL COOK, SECRETARY OF STATE, STATE OF MISSOURI, BY VIRTUE OF AUTHORITY VESTED IN ME BY LAW, DO CERTIFY AND DECLARE THAT ON THE 18TH DAY OF FEBRUARY, 1999, THE ABOVE FOREIGN LIMITED LIABILITY COMPANY IS DULY AUTHORIZED TO TRANSACT BUSINESS IN THE STATE OF MISSOURI AND IS ENTITLED TO ANY RIGHTS GRANTED LIMITED LIABILITY COMPANIES.

IN TESTIMONY WHEREOF, I HAVE SET MY HAND AND IMPRINTED THE GREAT SEAL OF THE STATE OF MISSOURI, ON THIS, THE 18TH DAY OF FEBRUARY, 1999.

THE GREAT SEAL OF THE STATE OF MISSOURI
MDCCCXX

Rebecca McDowell Cook
Secretary of State

$105.00

STATE OF MISSOURI

Rebecca McDowell Cook, Secretary of State
P.O. Box 778, Jefferson City, MO 65102
Corporation Division

FILED

FEB 18 1999

Rebecca McDowell Cook
SECRETARY OF STATE

Application for Registration of a Foreign Limited Liability Company

(Submit in duplicate with registration fee of $105.00)

(1) The name of the foreign limited liability company is:

MEP Pleasant Hill, LLC

(2) The name under which the foreign limited liability company will conduct business in Missouri is (must contain "limited company", "limited liability company", "LC", "LLC", "L.C.", or "L.L.C.") (must be filled out if different from name in line (1)):

MEP Pleasant Hill, LLC.

(3) The foreign limited liability company was formed under the laws of Delaware (state or jurisdiction) on the date of

January 28, 1999, and is to dissolve on January 28, 2029 (month/date/year or event)

(4) The purpose of the foreign limited liability company or the general character of the business it proposes to transact in this state is:

To engage in any and all lawful activities which foreign limited liability companies may perform in the State of Missouri.

(5) The name and address of the limited liability company's registered agent in Missouri is (this line must be completed and include a street address):

C T Corporation System, 120 South Central Avenue, Clayton, Mo 63105

Name — Address — City/State/Zip

The Secretary of State is appointed agent for service of process if the foreign limited liability company fails to maintain a registered agent. No failure to maintain a registered agent constitutes grounds to cancel the registration of the foreign limited liability company.

(6) The address of the registered office in the jurisdiction organized. If none required, then the principal office address of the foreign limited liability company is: c/o The Corporation Trust Company,

1209 Orange Street, Wilmington, DE 19801

Name — Address — City/State/Zip

(7) For tax purposes, is the limited liability company considered a corporation? ____ yes ____ no X

In affirmation thereof, the facts stated above are true.

John K. Brungardt
John K. Brungardt ____ Authorized signature (please sign and print name)

____ Authorized signature (please sign and print name)

____ Authorized signature (please sign and print name)

MO059 - CT System Online

Request for Proposals
for
Resource Specific Capacity & Energy
for
Missouri Public Service

Issued: May 22, 1998

A. General

UtiliCorp Energy Group is issuing this Request For Proposal (RFP) on behalf of Missouri Public Service (MPS), a division of UtiliCorp United Inc. (UCU).

MPS is an integrated electric and gas utility located in western Missouri and is a member of the Southwest Power Pool and the MOKAN power pool.

The following RFP is for both annual and seasonal **Resource Specific Capacity and Energy** resources. Financially firm energy proposals will not be accepted.

Resource Specific means the successful bidder must state the actual power *supply resource(s) that will provide the capacity and energy requested. The* resource(s) need not be stated in the proposal; however, the resource(s) must be named and listed in any contract which may result from this solicitation.

This RFP is not a contract. Any contract(s) which may result from this RFP shall be in accordance with mutually agreeable, specific terms and conditions developed between UtiliCorp and the successful bidder(s). In addition, any contract(s) resulting from this RFP shall be subject to the approval of all regulatory bodies having jurisdiction.

UtiliCorp reserves the right to reject any or all proposals at its sole discretion.

Proposals shall be marked confidential and three copies shall be sent to Kiah Harris at the following address. Proposals must be received no later than 5:00p.m. C.D.S.T., July 3, 1998.

Kiah Harris
Manager, Business Analysis and Consulting
Burns & McDonnell
9400 Ward Parkway
Kansas City, MO 64114

B. Contract Capacities and Periods

Proposals are requested for the seasonal and annual capacity amounts shown in Table 1. Note that UCU may purchase less than the amounts shown in Table 1.

Proposals for contract periods beginning June 1, 2002 or later must include a buyout option. The price of the option shall be stated in $/MW-mo.

Note that the while the annual capacity amounts represent the total resource need, the amounts listed under the three headings are not mutually exclusive. For example, assuming that appropriate proposals are submitted, UCU may elect to purchase one of the following or similar portfolios to meet the needs of MPS from 6/1/2000 - 5/31/2001, each of which would satisfy the total need of 325 MW:

- 100 MW of Jun-May capacity, 50 MW of Oct-May capacity and 175 MW of Jun-Sep capacity; or,
- 325 MW of Jun-Sep capacity and 75 MW of Oct-May capacity; or,
- 325 MW of Jun-May capacity.

Table 1: MPS Capacity Need

Contract Period		Capacity Amount (MW)		
		Seasonal Capacity		Annual Capacity
From	To	Jun-Sep	Oct-May	Jun-May
6/1/2000	5/31/2001	Up to 325	Up to 75	Up to 325
6/1/2001	5/31/2002	Up to 500	Up to 250	Up to 500
6/1/2002	5/31/2003	Up to 575	Up to 300	Up to 575
6/1/2003	5/31/2004	Up to 650	Up to 350	Up to 650

C. Point(s) of Delivery

The point(s) of delivery shall be the interconnection point(s) of the MPS transmission system with the Eastern Interconnection.

D. Capacity Pricing

Capacity price at the point(s) of delivery must be stated in $/MW-mo, fixed for the applicable contract term. Proposals in which the capacity price varies in each month of the contract period are acceptable.

E. Energy Pricing

Bidders are encouraged to submit creative pricing proposals. The energy price must be for energy delivered at the Point(s) of Delivery. Energy prices may be fixed or based on regionally recognized indices. The energy pricing methodology must enable UtiliCorp to determine the energy price prior to submitting a purchase schedule per Section H below.

Bidders may propose a variety of energy pricing methodologies which may include, but are not limited to, the following elements:

On peak/off peak price	Constant price
Monthly price	Index price
Resource heat rate	Resource variable O&M costs

The bidder shall provide any formula(s) used to calculate the energy price. The bidder shall include the values of any constants and a definition of all variables which make up the formula(s).

F. Buyout Option

A buyout option price must be provided for each contract period beginning on or after June 1, 2002. The pricing of the option shall stated in \$/MW-mo applicable to those months remaining in the contract period subsequent to exercising the option.

G. Transmission

The successful bidder shall provide firm transmission service from the proposed resource(s) to the Point(s) of Delivery.

H. Scheduling

Proposals which allow hourly schedule changes are preferred; however, UCU will consider any and all scheduling proposals. Bidders shall state what scheduling requirements are proposed. At a minimum, proposed requirements on the following items must be included in bidders proposal:

Resource Start up costs, if applicable
Minimum purchase schedule
Minimum load factor & measuring period
Maximum load factor & measuring period
Minimum schedule block
Initial schedule submittal procedure
Subsequent schedule change procedure
Energy Block Requirements (ie: 7x24, 5x16, etc.)

I. Availability

Bidders must state and define the guaranteed availability level for the resource(s) that will provide the capacity and energy proposed.

The successful bidder **will be required** to reimburse UtiliCorp any incremental cost incurred to acquire replacement capacity and energy due to the bidder's failure to meet its availability guarantees.

Bidders shall provide the proposed maintenance schedule for unit contingent resource(s).

J. *Contact*

For additional information regarding this RFP, contact Frank A. DeBacker as follows:

Ph:	(816) 936-8639
Fax:	(816) 936-8695
E-mail:	fdebacke2@utilicorp.com

APPENDIX 4

HIGHLY CONFIDENTIAL

APPENDIX 5

HIGHLY CONFIDENTIAL

HIGHLY CONFIDENTIAL

EXECUTIVE SUMMARY

The Power Sales Agreement (PSA) is a unit sale contract between MEPPH and MPS. The basic premise is that MEPPH is selling some or all of the output of a particular unit to MPS.

The principal features of the PSA are as follows:

1. **The power plant**. The power plant will consist of two combustion turbines, each with a nominal net capacity of 160 MW, a heat recovery steam generator, and a steam turbine. The latter two components add approximately 230 MW when the station is operating in combined cycle mode. The capacity payment covers the cost of interconnection with MPS (but not system reinforcements on MPS's side of the meter), with a possible adjustment if the cost of these facilities exceeds $2 million, and covers the cost of a connection, directly or through a local distribution company, with an interstate gas pipeline.

2. **Reserved capacity**. MEPPH is committed to provide, and MPS is committed to purchase, 320 MW from the two combustion turbines operating in simple cycle from June 1, 2001 to September 30, 2001, at a price of $5.70 per kilowatt-month ($/kW-mo.). The plant will then be taken off line for some or all of the remainder of 2001 to add the additional equipment so that it can begin operating in combined cycle mode on January 1, 2002. Beginning on that date, MEPPH is to provide and MPS is to purchase 200 MW in each month until the expiration of the contract on May 31, 2005 at a price of $5.90/kW-mo. In addition, MEPPH is to provide, and MPS is to purchase, an additional 300 MW during the summer periods covered by the PSA (April 1 to September 30 in 2002, 2003, and 2004, and April 1 to May 31 in 2005) at a price of $7.50/kW-mo.

3. **Energy**. Natural gas will be converted into electricity for a charge of $1.25 per MWh (in 1998 dollars indexed to the U.S. Department of Commerce Producer Price Index). An appendix to the PSA guarantees MPS that the heat rates will not exceed certain guaranteed low levels, and the benefit of lower actual heat rates is passed through to MPS. The contract heat rates will be adjusted for part-load operation (which is less efficient).

4. **Availability; energy from other sources**. If MEPPH does not provide equivalent availability of 94% for each of the Summer Period (April 1 to September 30 of each year during the contract term) and Winter Period (the other months of a calendar year), it will

have to make a payment to MPS that effectively reduces its capacity payments proportionally (that is, by the ratio of actual equivalent availability to 94%, times the applicable capacity payment, which is weighted in the case of the Summer Period to reflect the different prices for the 200 MW block and the 300 MW block). Forced Outages, Scheduled Maintenance Outages, and Planned Outages (maintenance outages for a short period on short notice to take care of a problem) all count against the 94%, but force majeure outages (whether affecting MEPPH or MPS) and outages due to MPS's failure to supply fuel are excluded from the calculation. No Scheduled Maintenance Outages are allowed between June 1 and September 30 in any year. At any time (that is, whether to provide energy according to MPS's schedule or to achieve the Commercial Operation Date in either simple cycle or combined cycle mode), MEPPH can provide energy from sources other than the facility, so long as MPS has sufficient capacity to accept the energy at the alternate delivery point. If MEPPH's decision to use an alternative source imposes a cost from gas suppliers or transporters on MPS, MEPPH must reimburse such cost.

5. **Option to purchase option to terminate or reduce capacity**. This title is not a typographical error. MPS will have the ability to purchase, within 30 days of executing this Agreement by making a fixed lump-sum payment, any one of four alternatives which will give MPS the right to purchase an option to reduce its contractual obligations to purchase some or all of the capacity (and associated energy) covered by this Agreement (this is the option to purchase an option). The four alternatives are different dates in the future on which MPS must decide whether or not to purchase the option to reduce its contractual obligations. MPS may purchase any of the alternatives for a portion of capacity less than the Contract Capacity, the cost determined on a pro rata basis. MPS is not obligated to purchase any of the above alternatives. The termination option provides the opportunity for MPS to purchase for $0.90 per kW month the option to reduce its contractual obligations covered by this Agreement. If the Termination Option is elected MPS agrees to pay the Project Company $0.90 per kW month for each of the 36 months commencing from June 1, 2002 to May 31, 2005 for the right to terminate the Agreement or to reduce its purchase obligation by blocks of twenty-five (25) MW for the Summer Period and ten (10) MW for the Winter Period. MPS agrees to pay the $0.90 per kW month fee irrespective of whether it chooses to exercise the Termination Option. The termination and capacity reduction option may be exercised only on June 1, 2002, June 1, 2003 or June 1, 2004 and shall be exercised by MPS by written notice not later than March 1 preceding the June 1 at which the termination or capacity reduction becomes effective. Should MPS elect to terminate its purchase of any portion of contracted capacity, the remaining $0.90 per kW month of future payments will be accelerated to the June 1 on which the termination is effective.

If MPS does not elect any of the four alternatives listed above, the Project Company agrees to price such an option at any future date if so requested in writing by MPS.

6. ***Emergency scheduling***. If an emergency occurs on the MPS system due to a generator outage at a time when MPS has scheduled less than the full contract capacity for the period (320 MW, 200 MW, or 500 MW), MPS can require MEPPH to ramp up (or withdraw from an alternative spot purchaser) such unutilized capacity in time to meet the requirements of the Southwest Power Pool (31 to 59 minutes).

7. **Force Majeure**. The definition of force majeure is conventional. Equipment failure is a force majeure event only if it results from another force majeure event. A force majeure event affecting either party will postpone the milestone dates in the contract (other than the end of the contract term), except that MPS can terminate if MEPPH is more than a year late in achieving the Commercial Operation Date due to force majeure (18 months in the case of damage to certain major pieces of equipment). MPS can also terminate under the same circumstances for a force majeure outage of 12 or 18 months after the Commercial Operation Date. MPS will continue to make capacity payments to MEPPH if MPS cannot accept energy from MEPPH due to a force majeure event affecting MPS, and will continue to make capacity payments to MEPPH during the shorter of 120 days or the "deductible" period under MEPPH's business interruption insurance during MEPPH force majeure outages.

8. **Dispute Resolution**. The contract calls for arbitration to resolve disputes unless the subject matter is under the primary jurisdiction of the Missouri Public Service Commission or the Federal Energy Regulatory Commission.

9. **Interconnection Agreement**. There will be a separate interconnection agreement between the parties.

10. **Damages**. Both parties waive incidental and consequential damages, and each party indemnifies the other against third-party claims.

CERTIFICATE

I, Nancy J. Schulte, hereby certify that I am Assistant Secretary of UtiliCorp United Inc. (the "Company") and custodian of the records and seal of such Company; that the attached resolutions are full, true and correct copies of resolutions adopted at a regular meeting of the Board of Directors of said Company on November 2, and November 3, 1999 and said resolutions are in full force and effect and have not been amended or revoked.

IN WITNESS WHEREOF, I have hereunto set my hand and the seal of said Company this 16th day of February, 1999.

Nancy J. Schulte
Assistant Secretary

<u>RESOLUTIONS</u>

Missouri Combined Cycle Project
Pleasant Hill, Mo.

WHEREAS, the Company has caused to be established MEP Investments, LLC. ("MEP") to engage in merchant energy activities, including the purchase and sale of power and construction of power plants; and

WHEREAS, MEP has submitted the lowest qualifying bid in connection with the construction of a 500 MW gas fired combined cycle "F" class generating facility (the "Project") to be located in Pleasant Hill, Missouri to sell power to Missouri Public Service ("MPS") pursuant to a power purchase agreement (the "Purchase Agreement"); and

WHEREAS, MEP now proposes to enter into construction and engineering contracts for the construction of the Project and enter into the Purchase Agreement with MPS; be it

RESOLVED, the Board approves the award of the Project to MEP subject to the terms and conditions set forth in the original request for proposal; and

RESOLVED FURTHER, that MEP is authorized to proceed with the project financing, acquisition, construction and operation of a gas fired generating facility to be located on land currently held on behalf of MEP in Pleasant Hill, Missouri, at development costs of approximately $224 million, (subject to adjustment); and

RESOLVED FURTHER, that in connection with the development of the Project, MEP is authorized to negotiate, execute and deliver such equipment agreements, construction agreements, engineering agreements, architects' agreements, consulting agreements, financing agreements, security agreements, fuel supply agreements, transport agreements, and other agreements and documents (collectively, the "Contracts") generally as may be necessary or appropriate for the purpose of constructing the Project; and

RESOLVED FURTHER, that the President, Chief Executive Officer or any vice president be, and each of them hereby is, authorized to negotiate, execute and deliver, on behalf of the Company, the Purchase Agreement upon substantially the terms set forth in the bid, with such changes in form or substance as the officer executing the same shall approve, such approval to be conclusively evidenced by her or his signature thereon; and

RESOLVED FURTHER, that to facilitate the development of the Project, said officers be, and each of them hereby is, authorized to determine whether the Company should participate as a coparty with MEP in any of the Contracts, or provide other support to MEP with regard to the Contracts; and

RESOLVED FURTHER, that the Company provide interim financing to MEP for the development of the Project, in such amounts and forms (as debt or equity) and upon such terms as said officers shall determine to be necessary or advisable, consistent with the intent of these resolutions; and

RESOLVED FURTHER, that the Company coordinate with MEP in the obtaining of all necessary permits and approvals, including regulatory approvals from federal, state and local governments, as may be required or appropriate for the purpose of carrying out the foregoing transactions; and

RESOLVED FURTHER, that said officers are further authorized to take such further action and to execute such additional agreements or instruments and to delegate said authority as may be necessary or appropriate in connection with carrying out the transactions contemplated by the foregoing resolutions.

j059legal99

STATE OF MISSOURI
PUBLIC SERVICE COMMISSION

At a Session of the Public Service Commission held at its office in Jefferson City on the 22nd day of April, 1999.

In the Matter of the Application of UtiliCorp United Inc. Under Section 32(k) of the Public Utilities Holding Company Act of 1935 Concerning a Proposed Power Sales Agreement Between MEP Pleasant Hill, L.L.C. and UtiliCorp United Inc. d/b/a Missouri Public Service.	)	<u>Case No. EM-99-369</u>

ORDER REGARDING POWER SALES AGREEMENT

On March 1, 1999, UtiliCorp United Inc. (UtiliCorp) d/b/a Missouri Public Service filed an Application with the Commission seeking an order of the Commission regarding a Power Sales Agreement (PSA) between UtiliCorp and MEP Pleasant Hill, L.L.C. (MEPPH). UtiliCorp proposes to enter into a PSA agreement with MEPPH whereby UtiliCorp would purchase electric power generated by MEPPH beginning on June 1, 2001. MEPPH is an exempt wholesale generator of electric power and is an affiliate of UtiliCorp.

Section 32(k) of the Public Utility Holding Company Act of 1935 (PUHCA), codified at 15 U.S.C. 79z-5a(k), provides that "an electric utility company may not enter into a contract to purchase electric energy at wholesale from an exempt wholesale generator if the exempt wholesale generator is an affiliate or associate company of the electric utility company." The federal statute then goes on to indicate that an electric utility company may enter into such a contract with an affiliate if every state commission having jurisdiction over the retail rates of such electric utility company makes certain specific determinations in advance of the electric utility company entering into such contract. UtiliCorp's Application asks that the Commission enter an order making the required specific determinations. Because of the need to begin construction of a combustion turbine generation plant by the end of July of 1999, UtiliCorp asked that the Commission issue its order regarding this Application no later than May 1, 1999.

On March 5, the Commission issued a Notice Establishing Time for Filing of Recommendation that directed the Staff of the Public Service Commission (Staff) to file its recommendation regarding approval or rejection of UtiliCorp's Application no later than April 5. The Office of the Public Counsel (Public Counsel) was also allowed until April 5 to file its recommendation.

On April 5, Staff filed two memorandums, one submitted by Michael S. Proctor, Chief Regulatory Economist for the Commission, and the other submitted by Mark L. Oligschlaeger, Regulatory Auditor V, and Steven Dottheim, Chief Deputy General Counsel. Both memorandums evaluate the PSA and recommend that the Commission approve UtiliCorp's application. Staff did, however, recommend that the Commission's approval be subject to several conditions. Public Counsel also filed its recommendation on April 5. Public Counsel recommended approval but only upon certain conditions. 4 CSR 240-2.080(12) provides that parties are allowed ten days from the date of filing in which to respond to any motion or pleading. No timely response was filed to the recommendations of either Staff or Public Counsel.

The Commission has reviewed and considered the Application filed by UtiliCorp and the recommendations of Staff and Public Counsel. The Commission finds that the Application of UtiliCorp should be granted subject to the conditions recommended by Staff and Public Counsel.

IT IS THEREFORE ORDERED:

1. That, in compliance with Section 32(k) of the Public Utility Holding Company Act of 1935, the Commission determines that:

   a) the Commission has sufficient regulatory authority, resources and access to books and records of UtiliCorp United Inc., MEP Pleasant Hill, L.L.C. and any relevant associate, affiliate or subsidiary company to exercise its duties under subparagraph (k) of Section 32 of the Public Utility Holding Company Act of 1935;

   b) the transaction will benefit consumers;

   c) the transaction does not violate any Missouri law;

   d) the transaction would not provide MEP Pleasant Hill, L.L.C. with any unfair competitive advantage by virtue of its affiliation or association with UtiliCorp United Inc.; and

   e) the transaction is in the public interest.

2. That the Commission's approval of UtiliCorp United Inc. d/b/a Missouri Public Service's Application is specifically conditioned upon the following conditions:

a) That UtiliCorp United Inc. shall make available to the Commission, its Staff and the Office of the Public Counsel, at reasonable times and reasonable places, all books and records and employees and officers of MEP Pleasant Hill, L.L.C. and any affiliate or subsidiary of UtiliCorp engaged in any activity with MEP Pleasant Hill, L.L.C.

b) MEP Pleasant Hill, L.L.C. shall employ accounting and other procedures and controls related to cost allocations and transfer pricing to ensure and facilitate full review by the Commission and its Staff and to protect against cross-subsidization of non-Missouri Public Service business by Missouri Public Service's customers.

c) This order is in no way binding on the Commission or any party regarding a future rate or earnings complaint case to contest the ratemaking treatment to be afforded the Power Sales Agreement. UtiliCorp United Inc. shall not seek to overturn, reverse, set aside, change or enjoin, whether through appeal or the initiation or maintenance of any action in any forum, a decision or order of the Commission which pertains to recovery, disallowance, deferral or ratemaking treatment of any expense, charge, cost or allocation incurred or accrued by MEP Pleasant Hill, L.L.C. or UtiliCorp United Inc. d/b/a Missouri Public Service in or as a result of the Power Sales

Agreement on the basis that such expense, charge, cost or allocation has itself been filed with or approved by the Federal Energy Regulatory Commission, or was incurred pursuant to the Power Sales Agreement.

3. That the Commission's approval of the instant Power Sales Agreement does not imply or assure approval of any future contracts to purchase electric energy at wholesale from an exempt wholesale generator that is an affiliate or associate company of an electrical corporation within the Commission's jurisdiction.

4. That UtiliCorp United Inc. is authorized to enter into, execute and perform in accordance with the terms and conditions of the proposed Power Sales Agreement by and between MEP Pleasant Hill, L.L.C. and UtiliCorp United Inc. d/b/a Missouri Public Service.

5. That UtiliCorp United Inc. is authorized to enter into, execute and perform in accordance with the terms of all documents reasonably necessary and incidental to the performance of the transactions that are the subject of the Application.

6. That this order shall become effective on May 4, 1999.

7. That this case may be closed on May 5, 1999.

BY THE COMMISSION

Dale Hardy Roberts
Secretary/Chief Regulatory Law Judge

(S E A L)

Lumpe, Ch., Murray, Schemenauer
and Drainer, CC., concur
Crumpton, C., absent

Woodruff, Regulatory Law Judge

SCHEDULE FAD-25
Page 6 of 8

STATE OF MISSOURI
OFFICE OF THE PUBLIC SERVICE COMMISSION

I have compared the preceding copy with the original on file in this office and I do hereby certify the same to be a true copy therefrom and the whole thereof.

WITNESS my hand and seal of the Public Service Commission, at Jefferson City,

Missouri, this 22ND day of APRIL, 1999.

Dale Hardy Roberts

Dale Hardy Roberts
Secretary/Chief Regulatory Law Judge

STATE OF MISSOURI
PUBLIC SERVICE COMMISSION
JEFFERSON CITY
April 22, 1999

CASE NO: EM-99-369

Office of the Public Counsel
P.O. Box 7800
Jefferson City, MO 65102

General Counsel
Missouri Public Service Commission
P.O. Box 360
Jefferson City, MO 65102

Gary Clemens
Utilitcorp United Inc.
10700 E. 350 Highway
Kansas City, MO 64138

James C. Swearengen
Paul A. Boudreau
Brydon, Swearengen & Englan P.C.
312 E. Capitol Ave.
Jefferson City, MO 65102

Enclosed find certified copy of ORDER in the above-numbered case(s).

Sincerely,

Dale Hardy Roberts

Dale Hardy Roberts
Secretary/Chief Regulatory Law Judge

Uncertified Copy:

MEMORANDUM

TO: Missouri Public Service Commission Official Case File
Case No. EM-99-369

FROM: Michael S. Proctor
Chief Regulatory Economist

Wess Henderson 4-5-99 Steven Dottheim 4/5/99
Director-Utility Operations Division/Date General Counsel's Office/Date

SUBJECT: Staff's Recommendation For Approval Of The Application Of UtiliCorp United, Inc. Under §32(k) Of The Public Utilities Holding Company Act Of 1935 Concerning A Proposed Power Sales Agreement Between MEP Pleasant Hill, L.L.C. And UtiliCorp United, Inc., d/b/a Missouri Public Service

DATE: April 5, 1999

Missouri Public Service Commission Determinations under §32(k) of PUHCA

In order for Missouri Public Service (MPS), a division of UtiliCorp United, Inc. (UtilCorp) to enter into a Power Sales Agreement (PSA) with Merchant Energy Partners Pleasant Hill, L.L.C. (MEPPH), a subsidiary of UtiliCorp, subsection 32(k) of the Public Utility Holding Company Act (PUHCA) of 1935 requires the Missouri Public Service Commission (Commission) to make the following determinations regarding the PSA:

1. it will benefit consumers;
2. it does not violate any state law;
3. it would not provide MEPPH any unfair competitive advantage by virtue of its affiliation or association with UtiliCorp; and
4. it is in the public interest.

The Commission must also make a determination that it has sufficient regulatory, resources and access to books and records of UtiliCorp and any relevant associate, affiliate or subsidiary company to exercise its duties under subparagraph 32(k)(2) of PUHCA. UtiliCorp in its Application at page 5, paragraph 11 states that:

. . . The Commission's existing rules and regulations permit it to examine the books and records of UtiliCorp. Furthermore, the Commission, its Staff and the Office of the Public Counsel may examine the books, accounts, contracts and records of MEPPH as required for the effective discharge of the Commission's regulatory responsibilities affecting the provision of electric service by MPS."

In this memorandum and the accompanying memorandum of Staff members Mark Oligschlaeger and Steve Dottheim, it will be shown that the PSA, subject to the review and ratemaking conditions proposed by the Staff, meets all four of the subsection 32(k) PUHCA standards.

1. The PSA will benefit consumers

The capacity from PSA between MPS and MEPPH is required to meet the capacity reliability needs of MPS customers and is therefore of benefit to consumers. What follows is a description of the process by which the Staff has determined that there is a capacity need which the PSA will meet to the benefit of consumers.

The Staff has met with MPS on a regular basis following UtiliCorp's initial resource plan filing[1] required by 4 CSR 240-Chapter 22. In these meetings, MPS has provided Staff with updates on load forecasts as well as other changes that have occurred in its resource acquisition plans. In its resource plan filing, MPS stated its intention to implement a competitive bidding process to acquire the capacity needed to meet the requirements of its customers for capacity and energy. This need comes from two sources: (1) load growth in the MPS service territory; and (2) expiration of existing purchased power contracts. Most of the changes in UtiliCorp's resource acquisition strategy have come in the timing of resource additions.

[1] In its 1995 Missouri Energy Plan filed in May 1995 in Case No. EO-95-187, UtiliCorp included supply-side options for 206 megawatts (MW) in combined cycle capacity for the summers of 2000 and 2001. The supply-side implementation plan strategy included a competitive-bidding process that was to be completed in 1997.

For the summer of 1999, MPS has accredited generation capacity of 1,047 MW with 280 MW of purchased power from existing purchased power contracts to meet a total capacity requirement[2] of 1,366 MW. Not directly related to this pleading, MPS is evaluating bids for purchased power of 50 MW to meet its capacity requirement for this summer. The contracts making up the 280 MW of purchase power will expire and not be available to meet load for the summer of 2000. Thus, there is clearly a need for either purchased power or MPS owned capacity starting with the summer of 2000.

It is important to note that the MPS purchase power acquisition strategy was split between meeting a short-term need and a long-term need. For the short-term (prior to the summer of 2001), MPS planned to enter into one- or two-year contracts for purchased power. Starting for the year 2001, MPS would seek longer-term contracts. In part, the rationale behind this strategy is that the short-term contracts would have to come from generating units that were already built, while the longer-term contracts would allow bids from new generating units that would not be available to supply power in the short-run.[3] The PSA between MPS and MEPPH is for a longer-term contract.

In the year 2001, MPS plans to improve the accredited capacity of its existing generating units from 1,047 MW to 1,085 MW. MPS plans to have a short-term purchase of 25 MW and begin the first year of its long-term contract with MEPPH with 320 MW of combustion turbine capacity. This provides a total capacity of 1,430 MW to meet a capacity requirement of 1,430. In the year 2002, the short-term purchased power contracts are terminated and the long-term

[2] The capacity requirement is the peak demand forecast, minus demand-side reductions such as interruptible load, plus a capacity reserve margin of 12 percent.

[3] How this strategy evolved is described in the third section of this memorandum.

contract with MEPPH goes up to 500 MW as MEPPH adds 180 MW of combined cycle capacity to the 320 MW of combustion turbines.

2. <u>The PSA does not violate any applicable state law</u>

Staff counsel has advised that state law does not prohibit any utility from purchasing power rather than building generation. In addition, Staff counsel has indicated that there is no state law that prohibits any electric utility from purchasing power from an affiliate.

3. <u>The PSA did not provide MEPPH any unfair competitive advantage by virtue of its affiliation with UtiliCorp</u>

As described below, the competitive bidding strategy employed by MPS involves a complex process that would more properly be described as a competitive negotiation. In addition, this process was flexible; allowing MPS to change its strategy as information became available. The Staff's limited observation/review of that process found no evidence to indicate that an unfair competitive advantage was afforded MEPPH.

As MPS developed its resource acquisition strategy for purchased power, the Staff made it clear that if an affiliate of UtiliCorp were to bid, that affiliate would need to be on a level playing field with all other potential bidders. This means no communications regarding the competitive bid between people representing the interests of MPS and those representing the interests of the affiliate, except through the formal competitive bidding/negotiation process. It also means that the affiliate would have to bid at the same time as others and that a transparent evaluation of the bids would need to take place.

The history of the competitive bidding/negotiation process for the long-term purchased power contract is as follows:

(1) Initial Request for Proposals was issued by MPS on May 22, 1998. At this time, MPS wanted capacity to be supplied beginning June 1, 2000 and go through May 31, 2004; i.e., a four-year contract, with capacity initially available for the summer of 2000.

(2) Eight proposals were received on July 3, 1998. The eight proposals were opened on July 6, 1998. One of the eight proposals was from Aquila Power Corporation (Aquila), a power-marketing subsidiary of UtiliCorp. Both Aquila and UtiliCorp/MPS have their principal offices and places of business at 10750 East 350 Highway, Kansas City, Missouri 64138. An outside consultant, Burns & McDonnell, a Kansas City engineering and consulting firm, reviewed all proposals. *Initial evaluation of the proposals was completed on* August 21, 1998 by Burns & McDonnell. On August 25, 1998, all bidders were requested to confirm their interest and update their proposals. All but three of the bidders (New Century Energies, Aquila and Basin Electric Cooperative) stated that they would not be able to provide capacity in time for the summer of 2000. From the three that could meet the summer 2000 requirement, the Basin Electric Cooperative bid was determined to not be cost effective because of its high capacity charge. In addition, UtiliCorp was in the process of negotiating purchased power for its West Plain's service territory in Kansas, for which it had received a bid from Sunflower Electric Cooperative (Sunflower) that included capacity that would be available for the June 2000 to May 2001 period. MPS made the decision to split its purchases between short-term capacity and long-term capacity, with the three bidders that could meet the short-term need (Aquila, New Century Energies and Sunflower) being included in the evaluation process for the short-term purchase power contracts.

(a) At this time, UtiliCorp concluded that it could build a generation plant at a lower cost than what it had received in bids from those who were proposing to supply from newly built generation. UtiliCorp was seriously considering building its own generation to meet the MPS long-term capacity need and in September 1998 formed MEPPH as a subsidiary to develop, own and manage UtiliCorp's portfolio of exempt wholesale generators (EWG), independent power producers (IPP) and cogeneration facilities and to possibly build and own generation for Missouri retail jurisdictional needs as an EWG. However, this capacity would not be available for the summer of 2000 and perhaps not even for the summer of 2001. The EWG option under consideration by MPS and the Aquila proposal for June 2001 through May 2004 were assigned to MEPPH.

(b) By November 3, 1998, the evaluation of the three short-term bids was completed with MPS determining that a combination of Sunflower and Aquila resources was the most cost effective.

(3) On November 6, 1998, MPS requested that bidders again confirm their interest and update their proposals that would begin supply in the summer of 2001. On November 30, 1998, only two of the eight companies submitted revised bids: Aquila Power/MEPPH and Houston Industries for the June 2001 through May 2006 period. These bids were evaluated by MPS as well as by its outside consultant, Burns & McDonnell. It was determined that the Houston Industries bid was not competitive. MPS contacted Houston Industries on December 21, 1998 to advise it that its bid was not cost effective and requested that it consider revising its

proposal. Houston Industries revised its proposal on January 6, 1999, and MPS received confirmation that MEPPH would replace Aquila as the owner of the proposed EWG and would be the entity contracting with MPS. MEPPH revised its proposal on January 12, 1999. It appears that in the evaluation/negotiation process, Houston Industries was given the first opportunity to revise its bid, and then MEPPH was given an opportunity to respond. The rational for this sequence is that the bidder with the non-competitive bid is allowed the first opportunity to make its bid competitive. After receiving the January 12, 1999 revision from MEPPH, MPS informed Houston Industries on January 13, 1999 that its revised bid was not competitive. On January 14, 1999, Houston Industries responded that it was not able to improve its offer. On January 15, 1999, Houston Industries was advised that it was not the successful bidder, and MPS awarded the contract to MEPPH, subject to further negotiations on final terms and conditions.

4. <u>The PSA is in the public interest</u>

The public interest is met when electricity is provided to end-use consumers at the lowest expected cost consistent with reasonable levels of risk associated with cost varying from its expected level. In today's environment of competitive wholesale power, properly implemented competitive bidding and/or negotiation for purchased power is a process by which least-cost acquisition of resources can be obtained. Based on the information presently available, the competitive bidding/negotiation process used by MPS appears to be consistent with obtaining the needed purchased power at least cost. Therefore, the Staff is willing to state that the PSA between MPS and MEPPH is in the public interest, subject to the conditions and ratemaking standards discussed below and in the accompanying recommendation, which will permit a detailed review of the transaction in the context of a rate increase or earnings complaint case.

It is important to note that the Staff has not evaluated the two proposals to determine which is least cost or whether accepting either of the two proposals would be a prudent management decision. Moreover, this Commission does not pre-approve the acquisition of resources by electric utilities. Instead, in its 1993 rulemaking on electric resource acquisition (4 CSR 240-Chapter 22), this Commission enacted rules that focused on the process, not the outcome. At the time these rules were adopted by the Commission, the Federal Energy Regulatory Commission (FERC) had not issued Order No. 888, which is premised on open transmission access on a non-discriminatory basis as being a means of fostering a competitive wholesale market for electricity. Thus, the Chapter 22 rules do not include any specific guidelines for competitive bidding or negotiations.

Since the Commission's adoption of 4 CSR 240-Chapter 22, there has been only one case in which the Commission was asked to evaluate whether or not the resource chosen by an electric utility was least cost prior to introducing the costs associated with the resource into rates.[4] This request that the Commission evaluate whether a resource chosen is least cost occurred because one of the options that was rejected by the utility was a cogenerator, and under the Public Utility Regulatory Policies Act of 1978 (PURPA), utilities are required to purchase from cogenerators that are competitive under an avoided cost criteria. Neither Houston Industries nor MEPPH are claiming to be a cogeneration facility. It is important to note that a review of the testimony submitted in that case indicates that a significant amount of analysis is required to determine which alternative is least cost.

[4] Alstrom Development Corporation vs. Empire District Electric Company, Case No. EC-95-28, Report And Order, 4 Mo.P.S.C.3d 187 (1995).

At this time, the Staff has not performed a detailed analysis of which of the two alternatives is least cost. Such an analysis should be done prior to the Commission approving the costs of the PSA in rates for Missouri Public Service customers. Subject to this condition, it is not necessary that this analysis be conducted at this time in order to determine whether or not the PSA is in the public interest. Moreover, to make such a determination at this time would put the Commission in the position of pre-approval of the prudency of MPS entering into the PSA, which is an approach that the Commission uniformly has rejected over many years. UtiliCorp in its Application recognizes and accepts the Commission's historical approach, wherein at paragraph 15, UtiliCorp states as follows:

> UtiliCorp understands that an order containing the findings required by the PUHCA with respect to the PSA shall in no way be binding on the Commission or any party to a future rate case to contest the ratemaking treatment to be afforded the PSA.

UtiliCorp also notes in its Application that:

(1) a copy of the RFP was forwarded to the Staff and the Office of the Public Counsel (Public Counsel) on August 24, 1998 for comment under the integrated resource plan format (page 3, paragraph 5 of Application);

(2) the eight (8) proposals received in response to the RFP were forwarded to the Staff and Public Counsel on August 24, 1998 under the integrated resource plan format (page 3, paragraph 6 of Application); and

(3) the reviews and evaluations of the proposals were provided to the Staff and Public Counsel on February 8, 1998 (page 3, paragraph 6 of Application).

As previously commented upon above, the 4 CSR 240-Chapter 22 rules focus on process, not outcome, and the review under these rules is not intended to have the Commission and its Staff engage in a contemporaneous evaluation with the utility of the proposals solicited to determine which is least cost or whether accepting any one of them would be a prudent management decision. Although the Commission generally has or can acquire sufficient regulatory resources to exercise its ratemaking duties when a utility seeks to reflect a resource decision in rates, the Staff does not want its position to be misinterpreted as indicating or implying that the Commission also has sufficient regulatory resources to exercise its ratemaking duties if utilities were to also seek pre-approval of their resource decisions.

The timing of the instant project to meet the June 1, 2001 on-line date is crucial. A determination of which of the options is least cost would involve a Staff analysis that at best could take several weeks, but more likely would take several months, to complete. If the results of the analysis were not in favor of approval of the PSA with MEPPH, written testimony and hearings would need to take place. All of this would put off the time at which MEPPH would initiate the building of the generating units required to meet the June 1, 2001 deadline for capacity.

The Staff believes that what is needed to determine that the PSA is in the public interest is a review of the process followed by MPS in acquiring the needed capacity. In the context of its ongoing efforts in reviewing the resource plans of MPS, the Staff believes that the process followed by MPS is adequate to meet the public interest standard, subject to the review and ratemaking conditions set out above and the accompanying Staff recommendation of Staff members Mark Oligschlaeger and Steve Dottheim.

Copies:
Bob Shallenberg, Director of Utility Services, Missouri Public Service Commission
Gordon Persinger, Director of Research & Public Affairs, Missouri Public Service Commission
Dan Joyce, General Counsel, Missouri Public Service Commission
Bill Washburn, Manager Electric Department, Missouri Public Service Commission
Gary Clemens, Manager Regulatory Services, UtiliCorp United Inc.
James C. Swearengen, Brydon, Swearengen & England P.C.
Paul A. Boudreau, Brydon, Swearengen & England P.C.
John B. Coffman, Office of the Public Counsel

MEMORANDUM

TO: Missouri Public Service Commission Official Case File
Case No. EM-99-369

FROM: Mark L. Oligschlaeger MLO
Regulatory Auditor V

Steven Dottheim SD
Chief Deputy General Counsel

MLO 4/5/99
Utility Services Division/Date

4/5/99
General Counsel's Office/Date

SUBJECT: Staff's Recommendation For Approval Of The Application Of UtiliCorp United, Inc. Under §32(k) Of The Public Utilities Holding Company Act Of 1935 Concerning A Proposed Power Sales Agreement Between MEP Pleasant Hill, L.L.C. And UtiliCorp United, Inc., d/b/a Missouri Public Service

DATE: April 5, 1999

I. INTRODUCTION

On March 1, 1999, UtiliCorp United, Inc. (UtiliCorp), d/b/a Missouri Public Service (MPS) filed an Application with the Missouri Public Service Commission (Commission) for an Order no later than May 1, 1999 that:

> (A) determines specifically that, in order to protect against abusive affiliate transactions, the Commission has sufficient regulatory authority, resources and access to books and records of UtiliCorp and Merchant Energy Partners Pleasant Hill, L.L.C. (MEPPH)[1] to exercise its duties under §32(k) of the Public Utility Holding Company Act of 1935 (PUHCA)[2] to ensure that a Power Sale Agreement (PSA) between UtiliCorp and MEPPH :
>
> (1) benefits consumers;

---

[1] UtiliCorp caused MEPPH to be established to engage in merchant energy activities, including the purchase and sale of power and construction of power plants. MEPPH will construct a 500 MW combined cycle combustion turbine generation plant in Cass County, Missouri near the town of Pleasant Hill, which plant will be operated by MEPPH in order to meet its contractual obligations under the PSA. UtiliCorp states in its Application that MEPPH (a) is not and will not be an "electrical corporation" in that it will sell electric power exclusively at wholesale, and, therefore, will not be engaged in the sale of electric power at retail to the general public, and (b) will be regulated by the Federal Energy Regulatory Commission (FERC) with respect to wholesale energy rates.

[2] Section 32(k) of PUHCA, 15 U.S.C. Section 79z-5a(k), is Section 711 of the Energy Policy Act of 1992.

(2) does not violate any state law;

(3) does not provide MEPPH with any unfair competitive advantage by virtue of its affiliation with UtiliCorp; and

(4) is in the public interest;

(B) authorizes UtiliCorp to enter into, execute and perform in accordance with the terms and conditions of the proposed PSA by and between UtiliCorp and MEPPH;

(C) authorizes UtiliCorp to enter into, execute and perform in accordance with the terms of all documents reasonably necessary and incidental to the performance of the transactions which are the subject of the Application; and

(D) grants such other authority as may be just and proper under the circumstances.

UtiliCorp seeks an Order by May 1, 1999 approving its Application because it asserts it is "imperative that MEPPH commence by the end of July of 1999 with the construction of the involved combustion turbine generation plant" so as to have in place the necessary capacity by 2001. MEPPH states that once it has obtained this Commission's approval, MEPPH will file with the FERC a request for certification as an exempt wholesale generator (EWG) and a request for approval of the PSA under the applicable provisions of PUHCA and the Federal Power Act (FPA).

Concurrent with the filing of this recommendation, the Staff is filing the recommendation of the Commission's Chief Energy Economist, Dr. Michael S. Proctor, who recommends that the Commission grant UtiliCorp the approvals requested in its March 1, 1999 Application in the instant docket, with conditions. The purpose of this document is to provide support for Dr. Proctor's recommendation and suggest additional conditions for the granting of the requested approvals.

II. STATE COMMISSIONS WHICH HAVE CONDITIONED PUHCA §32 FINDINGS

The Staff would not expect UtiliCorp's Application to cite to case law for authority for the Commission to grant the approvals requested by UtiliCorp with the conditions proposed by the Staff, but the Staff would note that the Application of UtiliCorp cites to no case law for anything other than one Missouri case respecting the determination of what constitutes a public utility. See UtiliCorp's Application at page 4, paragraph 9, citation to State ex rel. M.O. Danciger & Co. v. Public Serv. Comm'n, 205 S.W. 42 (Mo. 1918).

There is at least one state commission case on point and another related, both of which will be addressed herein regarding a state conditioning its granting of PUHCA §32 findings: Re Golden Spread Electric Cooperative, Inc., Docket No. 15100, Order, 176 PUR4th 587 (Tx.Pub.Util.Commn. 1997) and Re New England Power Co., DR 97-251, Order No. 22,982 (N.H.Pub.Util.Commn. 1998)(unreported decision).

In the Golden Spread Electric Cooperative case, Golden Spread Electric Cooperative, Inc. (Golden) filed in 1995 an application with the Texas Public Utility Commission (Texas PUC) seeking, among other things, the PUHCA §32(k) findings that were required in order for Golden to enter into a purchased power contract with an EWG that is an affiliate of Golden. The Golden contract with the EWG has a term of 25 years. The Texas PUC made the necessary PUHCA §32(k) findings, but conditioned the findings as they might be proposed to be related to stranded cost recovery and future purchased power contracts stating that its approval of the contract in question may not be relied upon as a basis for stranded cost recovery nor does approval imply or assure blanket approval of future purchased power costs. 176 PUR4th at 588. In particular regarding stranded cost recovery, the Commission found as follows:

> . . . the Commission finds that there is a risk of regulatory change during the life of the proposed power contracts. Consequently, Golden Spread Electric Cooperative, Inc. (Golden Spread or the Cooperative) may not rely on this Order as a basis for stranded cost recovery if and when such recovery becomes appropriate. . . . [Id.]

In the New England Power Co. case, New England Power Co. (NEP) requested that the New Hampshire Public Utilities Commission (New Hampshire PUC) authorize it to transfer its New Hampshire hydroelectric facilities, located in whole or in part in New Hampshire, to USGen New England, Inc. (USGenNE), in a proposed transaction in which NEP agreed to sell substantially all of its non-nuclear generating assets and unit entitlements. NEP is a Massachusetts corporation and a wholly owned subsidiary of the New England Electric System (NEES). It owns and operates generation and transmission facilities throughout Northern New England. NEP provides wholesale requirements service to affiliated retail electric utilities, including to Granite State Electric Company (GSEC) in New Hampshire. NEP sought certain "eligible facilities", i.e., EWG, findings from the New Hampshire PUC pursuant to PUHCA §32(c) to enable USGenNE to acquire NEP's generating assets without becoming subject to PUHCA. NEP stated that USGenNE made the receipt of EWG status a condition to the closing of the divestiture transaction.

PUHCA § 32(c) provides, in part, that if a rate or charge for electric energy produced by a facility was in effect under the laws of any state as of October 24, 1992, in order for the facility to be considered an eligible facility, every state commission having jurisdiction over any such rate or charge must make a specific determination that allowing such facility to be an eligible facility:

(1) will benefit consumers;

(2) is in the public interest; and

(3) does not violate state law.

PUHCA §32(c) also addresses the case where such rate or charge is a rate or charge of an affiliate of a registered holding company.

The New Hampshire PUC granted NEP's request for these findings relative to those facilities which NEP was transferring to USGenNE pursuant to the proposed divestiture transaction. The New Hampshire PUC premised its PUHCA §32 findings on the condition that USGenNE would agree to provide GSEC "transition service" consistent with the outcome of Docket No. DR 98 – 012. (Said docket was created to consider a settlement proposal relative to GSEC's compliance with the electric utility restructuring chapter of New Hampshire statutes.) Transition service was intended to (1) be a generation option for customers who did not choose to take generation service from a competitive provider and (2) provide GSEC's customers with stable prices as the competitive electric market developed. The New Hampshire PUC stated that by approving the NEP – USGenNE transaction, it was not implying that a similar approach should be adopted in the case of any other utility.

III. STAFF'S PROPOSED CONDITIONS

PUHCA §32(k) states in part that an electric utility company may enter into a contract to purchase electric energy at wholesale from an exempt wholesale generator (EWG) that is an affiliate or associate company if every state commission having jurisdiction over the retail rates of such electric utility company determines in advance of the electric utility company entering into such contract "that such commission has sufficient regulatory authority, resources and <u>access to books and records of the electric utility company and any relevant associate, affiliate or subsidiary company</u> to exercise its duties under this subparagraph." (Emphasis supplied). Thus, the Staff believes that two conditions that should be placed upon the Commission's approval of

UtiliCorp's Application so that the Commission will not be frustrated in carrying out its statutory duties should be the following:

(1) UtiliCorp shall agree to make available to the Commission and its Staff, at reasonable times and reasonable places, all books and records and employees and officers of MEPPH and any affiliate or subsidiary of UtiliCorp engaged in any activity with MEPPH.

(2) MEPPH shall agree to employ accounting and other procedures and controls related to cost allocations and transfer pricing to ensure and facilitate full review by the Commission and its Staff and to protect against cross-subsidization of non-MPS businesses by MPS customers.

FERC has jurisdiction over wholesale electric energy transactions. A state commission must allow, as reasonable operating expenses, costs incurred by a utility as a result of paying a FERC-determined wholesale rate. Nantahala Power and Light Co. v. Thornburg, 476 U.S. 953 (1986). FERC approval of an energy supplier's rate does not necessarily mean it was reasonable for the purchaser to incur the expense. A state commission can challenge the prudence of a utility's decision to purchase power at a FERC-approved rate under what has become known as the Pike County doctrine. Pike County Light and Power Co. v. Pennsylvania Pub. Util. Commn, 465 A.2d 735 (Pa. 1983). The Staff also would note that a state commission must defer to certain FERC approved allocations contained in operating or system agreements among affiliates of a registered holding company. Mississippi Power & Light Co. v. Mississippi ex rel. Moore, 487 U.S. 354 (1988).

UtiliCorp in its Application in the instant proceeding recognizes and accepts the Commission's historical approach of not granting pre-approval of electric resource additions, wherein UtiliCorp states, at paragraph 15 of its Application, as follows:

> UtiliCorp understands that an order containing the findings required by the PUHCA with respect to the PSA shall in no way be binding on the Commission

> or any party to a future rate case to contest the ratemaking treatment to be afforded the PSA.

Nonetheless, there is more than pre-approval that is occurring with UtiliCorp's proposed transaction.

As a result of the Nantahala Power and Light Co. and Mississippi Power & Light Co. cases, the Staff believes that Commission use of the language contained in paragraph 15 of UtiliCorp's Application is not an adequate condition to the Commission making the PUHCA §32(k) findings. The Staff believes that the following additional condition should be placed upon the Commission's approval of UtiliCorp's Application for an Order respecting the PSA between UtiliCorp and MEPPH. The Commission's approval of UtiliCorp's Application should be contingent upon the following occurring:

> (3) UtiliCorp shall agree that an order containing the findings required by the PUHCA with respect to the PSA shall in no way be binding on the Commission or any party to a future rate or earnings complaint case to contest the ratemaking treatment to be afforded the PSA. UtiliCorp shall agree that it will not seek to overturn, reverse, set aside, change or enjoin, whether through appeal or the initiation or maintenance of any action in any forum, a decision or order of the Commission which pertains to recovery, disallowance, deferral or ratemaking treatment of any expense, charge, cost or allocation incurred or accrued by MEPPH or MPS in or as a result of the PSA on the basis that such expense, charge, cost or allocation has itself been filed with or approved by the FERC, or was incurred, pursuant to the PSA.

Finally, the Staff would recommend that the Commission adopt the following condition in order that Commission approval of the instant Application, should that occur, not be used as authority for the approval of any subsequent PUHCA §32(k) application:

(4) The Commission's approval of the instant PSA does not imply or assure approval of any future contracts to purchase electric energy at wholesale from an EWG that is an affiliate or associate company of an electrical corporation within the Commission's jurisdiction.

Copies:

Bob Schallenberg, Director of Utility Services, Missouri Public Service Commission
Gordon Persinger, Director of Research & Public Affairs, Missouri Public Service Commission
Dan Joyce, General Counsel, Missouri Public Service Commission
Bill Washburn, Manager Electric Department, Missouri Public Service Commission
Gary Clemens, Manager Regulatory Services, UtiliCorp United, Inc.
James C. Swearengen, Brydon, Swearengen & England, P.C.
Paul A. Boudreau, Brydon, Swearengen & England, P.C.
John B. Coffman, Office of the Public Counsel

Martha S. Hogerty
Public Counsel

State of Missouri

Mel Carnahan
Governor

APR 05 1999
BRYDON, SWEARENGEN
& ENGLAND P.C.

Office of the Public Counsel
Harry S Truman Building
Ste. - 250
P.O. Box 7800
Jefferson City, Missouri 65102

Telephone: 573-751-4857
Facsimile: 573-751-5562
Relay Missouri
1-800-735-2966 TDD
1-800-735-2466 Voice

April 5, 1999

Mr. Dale Hardy Roberts
Secretary/Chief Regulatory Law Judge
Missouri Public Service Commission
P. O. Box 360
Jefferson City, MO 65102

RE: UtiliCorp United, Inc. d/b/a Missouri Public Service
Case No.: EM-99-369

Dear Mr. Roberts:

Enclosed for filing in the above referenced case, please find the original and 14 copies of the **Public Counsel Recommendation.** Please "file stamp" the extra enclosed copy and return it to this office. I have on this date mailed, faxed, or hand-delivered the appropriate number of copies to all counsel of record.

Thank you for your attention to this matter.

Sincerely,

John B. Coffman
Deputy Public Counsel

JBC:rjr

COPY

cc: Counsel of Record
Enclosure

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of the Application of UtiliCorp United, Inc. under Section 32(k) of the Public Utilities Holding Company Act of 1935 Concerning a Proposed Power Sales Agreement Between MEP Pleasant Hill, L.L.C. and UtiliCorp United Inc. d/b/a Missouri Public Service.	)	**Case No. EM-99-369**

PUBLIC COUNSEL RECOMMENDATION

COMES NOW the Office of the Public Counsel ("Public Counsel") and for its recommendation states as follows:

1. On March 1, 1999, UtiliCorp United, Inc. d/b/a Missouri Public Service ("Company") filed an Application requesting that the Public Service Commission ("Commission") make specific determinations regarding a proposed Power Sales Agreement ("PSA"). These determinations that are a prerequisite to approval of the PSA by the Federal Energy Regulatory Commission ("FERC"). Federal law ("PUHCA") requires these determinations be made by a state commission whenever an electric utility proposes a PSA with an affiliated exempt wholesale generator ("EWG"). Company is proposing a Power Sales Agreement ("PSA") between it and its affiliate MEP Pleasant Hill, L.L.C. ("MEPPH"). On March 5, 1999, the Commission requested recommendations regarding the approval or rejection of UtiliCorp's Aplication by April 5, 1999.

2. Company is accordingly requesting that the Commission specifically determine that it has sufficient regulatory authority:

> ...the Commission has sufficient regulatory authority, resources and access to books and records of UtiliCorp and MEPPH to exercise its duties under section 32(k) of PUHCA to ensure that the proposed PSA (i) benefits consumers, (ii) does not violate any state law, (iii) does not provide MEEPPH with any unfair competitive advantage by virtue of its affiliation with UtiliCorp and (iv) is in the public interest; (B) authorizing UtiliCorp to enter into, execute and perform in accordance with the terms and conditions of the proposed Power Service Agreement by and between MEPPH and UtiliCorp; (C) authorizing UtiliCorp to enter into, execute and perform in accordance with the terms of all documents reasonably necessary and incidental to the performance of the transactions which are the subject of this Application; and (D) granting such other authority as may be just and proper under the circumstances. (Application, pp. 6-7).

3. Public Counsel recommends that the Commission make these requested determinations only upon certain conditions. The fact that Company is proposing a PSA with an affiliate (MEPPH) raises concerns that it may not be in the public interest. Public Counsel believes that the Commission should ensure that the cost advantage purported to be gained from this transaction is not outweighed by the potential negative impacts to Company's captive ratepayers. It is not as simple to monitor and determine the impact on the public from such an affiliate transaction as it is when the transaction occurs between entities that are wholly separate. The monitoring of yet another affiliate transaction will require the expenditure of additional regulatory resources.

4. Public Counsel is also concerned about the potential detrimental effects on wholesale and retail markets in Company's region. Such detrimental effects could develop as a result of an over-concentration of the ownership of generation facilities. As market power is

accumulated under one parent company, the potential harm to consumers in a future competitive retail marketplace grows.

5. Because of the concerns raised about the structure of the proposed PSA, Public Counsel urges the Commission to make the requested determinations in a very specific manner. Particularly, the Commission should require Company to assure the Commission that it would still retain jurisdiction over any and all generation costs that would be passed on to its regulated customers through retail rates. Company should also acknowledge that FERC jurisdiction does not supercede the Commission's ability to review and disallow any purchased power costs that are found to be imprudent or unreasonable after a proper review and hearing on the prudency of the costs and rate impact of such costs. In particular, Public Counsel has concerns that the pricing adjustment provisions contained in subsections (a) and (b) of section 5.1 of Article 5 constitute an inappropriate shifting of risk to the purchaser, UtiliCorp United, Inc.

6. Furthermore, Company should assure that the Commission and Public Counsel have full and unfettered access to all the books and records of Company and MEPPH in order to protect the public interest.

WHEREFORE, Public Counsel respectfully submits its recommendation that the Commission approve the proposed application only if it receives the specific assurances set out above from Company and MEPPH.

Respectfully submitted,
OFFICE OF THE PUBLIC COUNSEL

BY: ______________________________

John B. Coffman (Bar No. 36591)
Deputy Public Counsel
Harry S Truman Bldg., Suite 205
301 West High Street, Box 7800
Jefferson City, MO 65102
Telephone: (573) 751-5565
Facsimile: (573) 751-5562

CERTIFICATE OF SERVICE

I hereby certify that the foregoing document has been either faxed, mailed, or hand-delivered to the following counsel of record on this 5th day of April, 1999:

Dana K. Joyce
General Counsel
Missouri Public Service Commission
P. O. Box 360
Jefferson City, MO 65102

James C. Swearengen // Paul A. Boudreau
Brydon, Swearengen & England, P.C.
312 East Capitol Avenue, Box 456
Jefferson City, MO 65102-0456

Gary Glemens
UtiliCorp United, Inc.
10700 East 350 Highway
Kansas City, MO 64138

____

HOGAN & HARTSON

L.L.P.

FILED
OFFICE OF THE SECRETARY

99 MAY -6 PM 2:53

FEDERAL ENERGY
REGULATORY
COMMISSION

JOHN R. LILYESTROM
PARTNER
(202) 637-5633
JRLILYESTROM@HHLAW.COM

May 6, 1999

COLUMBIA SQUARE
555 THIRTEENTH STREET, NW
WASHINGTON, DC 20004-1109
TEL (202) 637-5600
FAX (202) 637-5910

<u>CONTAINS PRIVILEGED INFORMATION – DO NOT RELEASE</u>

BY HAND DELIVERY

The Honorable David P. Boergers
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: MEP Pleasant Hill, LLC Docket No. ER99-2833 (Power Sales Agreement)

Dear Secretary Boergers:

MEP Pleasant Hill, LLC ("MEPPH") and UtiliCorp United Inc. ("UtiliCorp"), on behalf of its Missouri Public Service ("MPS") operating division, hereby jointly transmit to the Federal Energy Regulatory Commission ("Commission") in the above-captioned proceeding an original and five copies of a Power Sales Agreement between MEPPH and UtiliCorp d/b/a MPS dated February 22, 1999.

The Power Sales Agreement provides for the sale by MEPPH to MPS of 320 MW of capacity and associated energy for the period June 1, 2001 to September 30, 2001; 200 MW of capacity and associated energy for the months of January through March of the years 2002 through 2005 and the months of October through December of the years 2002 through 2004; and 500 MW of capacity and associated energy for the months of April through September of the years 2002 through 2004 and for the months of April and May in the year 2005. The capacity and energy will be from a generating facility to be constructed, owned and operated by MEPPH at a site in Pleasant Hill, Missouri. MEPPH is today filing an application for Exempt Wholesale Generator ("EWG") status with respect to the Pleasant Hill facility. The Power Sales Agreement contains market-based rates.

MEPPH is a subsidiary of UtiliCorp. Therefore, the sale to MPS is an affiliate transaction that must be filed with the Commission under section 205 of the Federal Power Act.

The Power Sales Agreement includes the following prices for capacity:

1. 320 MW for the period June 1, 2001 - September 30, 2001 - $5.70/kW-month

2. the initial 200 MW for the period January 1, 2002 - May 31, 2005 - $5.90/kW-month

3. the additional 300 MW for the periods April 1, 2002 - September 30, 2002; April 1, 2003 - September 30, 2003; April 1, 2004 - September 30, 2004; and April 1, 2005 - May 31, 2005 - $7.50/kW-month

Energy is supplied pursuant to a tolling arrangement. MPS will supply, at its own expense, the natural gas necessary to generate energy for delivery under the Power Sales Agreement. In addition, MPS will pay MEPPH $1.25 per MWh (in 1998 dollars). MPS is also responsible for the actual costs of transmission. 1/

As explained herein and in the attached affidavit of Frank A. DeBacker, Vice President - Fuel and Purchased Power for UtiliCorp, the MPS decision to purchase energy and capacity from MEPPH and the terms and conditions of the Power Sales Agreement were considered and negotiated strictly at arms' length. MPS determined, after a lengthy capacity and energy procurement process, that the MEPPH offer represents the lowest-cost option for such purchase. As such, the instant contract satisfies the requirements of the Commission for demonstrating that an affiliate power sale is just and reasonable and not unduly discriminatory.

On April 22, 1999, the Public Service Commission of the State of Missouri ("MPSC") issued an order approving the Power Sales Agreement, finding that the Agreement is in the public interest, and making the other specific findings required pursuant to section 32(k) of the Public Utility Holding Company Act ("PUHCA"), 15 U.S.C. § 79z-5a(k) (1994).

Communications concerning this filing should be addressed to each of the following:

1/ MEPPH has separately executed a transmission interconnection agreement with MPS that will be filed with the Commission at a later date.

On behalf of MEPPH:

Rob H. Freeman
Vice President - Capital
Finance/Legal Affairs
Aquila Merchant Energy Partners
10750 East 350 Highway
Kansas City, Missouri 64138

John B. O'Sullivan
Chadbourne & Parke LLP
1200 New Hampshire Ave., N.W.
Washington, D.C. 20036

On behalf of UtiliCorp:

Laurie J. Hamilton
Vice President - Regulatory Services
UtiliCorp United Inc.
10700 East 350 Highway
Kansas City, Missouri 64138
(816) 737-7151

John R. Lilyestrom
Hogan & Hartson L.L.P.
Columbia Square
555 13th Street, N.W.
Washington, D.C. 20004-1109
(202) 637-5633

List Of Documents Submitted

This filing consists of (1) this letter, (2) the Power Sales Agreement, (3) the affidavit of Frank DeBacker demonstrating that the Power Sales Agreement was negotiated at arms' length and represents the least expensive supply option available to MPS for the 2001-2005 period, (4) the April 22, 1999 order of the MPSC approving the Power Sales Agreement, and (5) a form of notice suitable for publication in the Federal Register.

Proposed Effective Date

Pursuant to 18 C.F.R. § 35.11 (1998), UtiliCorp requests waiver of the prior notice requirement to permit the Power Sales Agreement to be made effective June 1, 2001. 2/ UtiliCorp and MEPPH are filing the Power Sales Agreement at this early date in order to ensure that the required regulatory authorizations are in hand before substantial expenses are incurred with respect to the construction of the Pleasant Hill facility. MEPPH has already begun incurring such expenses and expects that the expenses will increase dramatically in July and August of this year. Ordering of major equipment, with associated reservation payments, is under

2/ June 1, 2001 is the scheduled date for initial deliveries of energy and capacity under the Power Sales Agreement. Other obligations under the Power Sales Agreement that do not involve the jurisdictional delivery of energy or capacity become effective prior to June 1, 2001.

division. UtiliCorp provides retail electric service to customers in British Columbia, Canada through its subsidiary West Kootenay Power Ltd. UtiliCorp also provides retail electric service to customers in the Waikato region of New Zealand and suburban areas of Melbourne, Australia through ownership interests held by UtiliCorp subsidiaries.

MEPPH, an indirect, wholly owned subsidiary of UtiliCorp, is a limited liability company organized under and by virtue of the laws of Delaware. MEPPH's direct parent is MEP Investments, LLC. MEP Investments, LLC has filed with the Commission an application for authorization to sell energy and capacity at market-based rates. That application is currently pending in Docket No. ER99-2322-000. The Commission has previously concluded that UtiliCorp and its affiliates lack market power in any relevant generation market and have adequately mitigated transmission market power by having open access transmission tariffs on file with the Commission. 3/ The Commission has further concluded that barrier to entry considerations do not preclude the sales of power at market-based rates by UtiliCorp and its affiliates.

Required PUHCA Findings

Pursuant to section 32(k) of PUHCA, an electric utility company (such as MPS) may enter into a contract to purchase electric energy at wholesale from an affiliated EWG (such as MEPPH) only if the state commission(s) with jurisdiction over the electric utility company's retail rates make certain specified findings. On March 1, UtiliCorp filed the Power Sales Agreement with the MPSC, requesting that the MPSC issue an order with the required findings. On April 22, the MPSC approved UtiliCorp's application, and made the following required findings:

> [I]n compliance with Section 32(k) of the Public Utility Holding Company Act of 1935, the [MPSC] determines that:
>
> a) the [MPSC] has sufficient regulatory authority, resources and access to books and records of UtiliCorp United Inc., MEP Pleasant Hill, L.L.C. and any relevant associate, affiliate or subsidiary company to exercise its duties under subparagraph (k) of Section 32 of the Public Utility Holding Company Act of 1935;

3/ UtiliCorp United Inc., 85 FERC ¶ 61,343 (1998).

b) the transaction will benefit consumers;

c) the transaction does not violate Missouri law;

d) the transaction would not provide MEP Pleasant Hill, L.L.C. with any unfair competitive advantage by virtue of its affiliation or association with UtiliCorp United Inc.; and

e) the transaction is in the public interest. 4/

A copy of the MPSC order is attached to this application.

Affiliate Abuse/Reciprocal Dealing

Pursuant to 18 C.F.R. § 35.27 (1998) of the Commission's regulations, a public utility seeking to make sales for resale at market-based rates from generation to be constructed on or after July 9, 1996 is not required to make any showing of a lack of market power. Therefore, the only issue before the Commission in considering the Power Sales Agreement is whether the agreement is the result of improper self-dealing or affiliate abuse. The Commission has explained that "in cases where affiliates are entering agreements for which approval of market-based rates is sought, it is essential that ratepayers be protected and that transactions be above suspicion in order to ensure that the market is not distorted." 5/ As explained in the attached affidavit of Frank A. DeBacker, the Power Sales Agreement represents the lowest cost capacity and energy supply option available to MPS following an extensive arms' length RFP process. At all times during the process, MPS treated MEPPH as it would any unaffiliated third party.

The Power Sales Agreement represents the lowest cost supply option for MPS and its ratepayers for the period from June 1, 2001 to May 31, 2005. 6/ Of

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4/ In the matter of the Application of UtiliCorp United Inc., Case No. EM-99-369, slip op. at 3 (April 22, 1999)

5/ Boston Edison Co. Re: Edgar Electric Energy Co., 55 FERC ¶ 51,382, at 62,167 (1991).

6/ In Boston Edison, the Commission described three nonexclusive examples of ways to demonstrate lack of affiliate abuse: (1) evidence of direct head-to-head the eight proposals submitted in response to the MPS RFP, only MEPPH's proposal met all of the seven criteria specified in the RFP. Moreover, following rigorous analysis, MPS determined that the final MEPPH proposal was the lowest cost option offered. 7/

Moreover, Mr. DeBacker explains that the pricing in the Power Sales Agreement is significantly below current market prices for the summer 1999 and 2000 periods, and prices can be expected to increase for the summer 2001 period as capacity margins become even tighter. Significantly, the MPSC, the regulatory body with the primary responsibility to protect the interests of MPS's retail customers, has concluded that the Power Sale Agreement is in the public interest.

Thus, in addition to the protections against affiliate abuse resulting from the RFP process, current market indicia indicate that the Power Sales Agreement represents relatively low-cost capacity and energy for the 2001 to 2005 period. As such, the Power Sales Agreement is just and reasonable and not unduly discriminatory. For all of these reasons, MEPPH and UtiliCorp request that the Commission accept the Power Sales Agreement for filing without modification.

In addition, MEPPH is today filing in a separate docket a rate schedule to permit sales of excess capacity and energy from the Pleasant Hill facility to non-affiliated third parties at market-based rates. That filing contains a code of conduct governing MEPPH's interactions with its franchise public utility affiliates. The code is essentially the same as the code on file with the Commission for AEMC. One modification to the AEMC code is to permit MEPPH and MPS to share scheduling and other operational information regarding the Pleasant Hill facility to the extent necessary to implement the Power Sales Agreement.

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competition between the seller and competing unaffiliated suppliers in either a formal solicitation or in an informal negotiation process; (2) evidence of the prices that nonaffiliated buyers were willing to pay for similar services from the seller; or (3) benchmark evidence of the market value, based on both price and nonprice terms and conditions, of contemporaneous sales made by nonaffiliated sellers for similar services in the relevant market. As described above, Mr. DeBacker provides extensive evidence under option (1), as well as evidence of current market prices under option (3).

7/ As Mr. DeBacker explains, MEPPH's proposal was split into two separate components. The initial portion, for the period from June 2000 to May 2001, is covered by a separate agreement with another UtiliCorp affiliate. That agreement is before the Commission in Docket No. ER99-2235-000.

REQUEST FOR PRIVILEGED TREATMENT

Certain exhibits to the attached affidavit of Frank DeBacker contain privileged information. Pursuant to Section 388.112 of the Commission's regulations, Applicants request privileged treatment for Exhibits 3-9 to Mr. DeBacker's affidavit. Because these exhibits contain highly sensitive and confidential commercial information regarding offers of third parties to sell MPS energy and capacity, the disclosure of which would harm Applicants and the affected third parties if publicly released, it is exempt from the mandatory public disclosure requirements of the Freedom of Information Act. Undersigned counsel should be contacted with respect to any matters related to this request for privileged treatment of Exhibits 3-9. As required under Rule 388.112, the original copy of this filing, containing all confidential privileged information, is filed under seal. The five copies are filed with the privileged information removed, with the required indications where such information has been removed.

Respectfully submitted,

John R. Lilyestrom
Counsel for UtiliCorp United Inc.

Attachments

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

MEP Pleasant Hill, LLC) Docket No. ER99-__

NOTICE OF FILING

Take notice that on May 6, 1999, MEP Pleasant Hill, LLC ("MEPPH") and UtiliCorp United Inc. ("UtiliCorp"), on behalf of its Missouri Public Service ("MPS") operating division, jointly filed a Power Sales Agreement between MEPPH and UtiliCorp (MPS) dated February 22, 1999.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 385.211, 385.214). All such motions or protests should be filed on or before ______________, 1999. Protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

David P. Boergers
Secretary

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

MEP Pleasant Hill, LLC) Docket No. ER99-_____

AFFIDAVIT OF
FRANK A. DEBACKER

STATE OF MISSOURI)
)
COUNTY OF JACKSON)

The undersigned, being first duly sworn states as follows:

I, Frank A. DeBacker, to the best of my knowledge and belief, hereby attest to the following:

1. I am employed as Vice President - Fuel and Purchased Power for UtiliCorp United Inc. ("UtiliCorp"). My business address is 10750 East 350 Highway, Kansas City, MO 64138. I am responsible for arranging and negotiating long-term power supply purchases for UtiliCorp's regulated utility operations and fuel supply for UtiliCorp's regulated coal-fired generation facilities.

2. The purpose of this affidavit is to describe the process that led to the negotiation and execution of the Power Sales Agreement between MEP Pleasant Hill, LLC ("MEPPH") and UtiliCorp ("MPS") dated February 22, 1999. This affidavit summarizes the evaluation process and the results of the supply side resource acquisition process for UtiliCorp's Missouri Public Service division ("MPS") begun in May, 1998 to met MPS capacity needs beginning June 1, 2000.

3. MPS will face a significant capacity shortfall beginning in June 2000 due to the expiration of two of its three purchase power contracts (from Kansas City Power & Light and Associated Electric Cooperative). The total capacity provided by these two contracts is 280 MW. Another contract, with Union Electric Company ("UE"), for 115 MW of capacity terminated on March 1, 1999. A summary of the MPS loads and resources forecast showing the capacity shortfall is included as Exhibit 1.

4. In order to meet both the capacity shortfall triggered by the expiration of the above contracts and projected increases in load, MPS issued a Request for Proposal ("RFP") for additional supply side resources on May 22, 1998. Proposals were due on July 3, 1998. As originally issued, the RFP solicited proposals to meet the projected capacity and energy needs for the June, 2000 to May, 2004 time period. A copy of the original RFP is included as Exhibit 2. Neither MEPPH nor any other UtiliCorp affiliate that was a potential bidder had any involvement whatsoever in the development of the RFP.

5. Eight proposals were received in response to the RFP. Brief summaries of each proposal together with the original proposal and subsequent revisions are contained in Exhibit 3. Given the commercially sensitive nature of the proposals, I will refer herein to respondents other than UtiliCorp's affiliate Aquila Energy Marketing Corporation ("AEMC") 1/ by letter. Exhibit 4 to my affidavit, which will be filed under seal, identifies each of these seven parties.

6. In order that evaluation criteria be consistently applied to all proposals, the RFP contained specific requirements in the following areas:

A. Resource Specific:	Bidder must be able to name the specific resource(s) which would supply the capacity and energy. "Financially Firm" proposals were not acceptable.
B. Buyout Option:	Proposal must offer the option to decrease the capacity commitment at a future date.
C. Delivery Point:	Proposals shall include the cost of transmission from the resource to the borders of the MPS transmission system.
D. Capacity Pricing:	Capacity price shall be known and fixed for each period. An indexed capacity price was not acceptable.
E. Energy Pricing:	The energy pricing formula must be such that MPS would know the cost of energy prior to submitting an energy purchase schedule.
F. Availability:	Availability of capacity and energy must be guaranteed with reductions in capacity payments for failure to meet guarantee levels.

1/ As explained below, AEMC eventually assigned the portion of its bid for the period from June 1, 2001 to May 31, 2005 to another UtiliCorp affiliate, Merchant Energy Partners, which in turn established MEPPH as the entity to perform under the Power Sales Agreement.

G. Contract Term Four years or less.

MPS selected these criteria to ensure that the purchased capacity and energy would meet MPS' needs while minimizing the risks of excessive costs for MPS ratepayers. The criteria called for relatively fixed prices for energy and capacity from designated specific resources. The criteria were not designed to favor any particular power supplier, either MEPPH or anyone else.

7. The following table shows how the each of the eight proposals complied with or otherwise addressed each of the seven criteria listed above. As can be seen from the table, only the AEMC proposal complied with all criteria. All remaining proposals did not comply with one or more of the criteria.

Proposal Compliance with RFP Criteria

Bidder Name	Criteria						
	A	B	C	D	E	F	G
AEMC	Y	Y	Y	Y	Y	Y	1-4
Party B	Y	N	Y	Y	Y	N	4
Party C	Y	A	Y	Y	Y	Y	10
Party D	Y	Y	N	Y	Y	N	3
Party E	Y	N	N	Y	Y	N	3
Party F	Y	A	N	Y	Y	Y	3
Party G	Y	Y	Y	Y	Y	N	4
Party H	Y	N	Y	Y	Y	A	4

Notes: Y = Yes, N = No, A = Addressed but no specific terms
Parties C, D, E, and F contract terms begin 6/1/2001.
Only AEMC and Parties B, G, and H are available beginning 6/1/2000.

8. The unanticipated supply shortages and subsequent increase in market price and volatility of the summer of 1998 had significant impact on critical elements of the resources selection and evaluation process. The more important events are described below. Exhibit 5 contains a chronology of the evaluation process and provides added insight into the evaluation process.

9. The changing wholesale market gave rise to the following events which had significant impact on the evaluation process.

   A. In mid-September 1998, UtiliCorp formed Merchant Energy Partners ("MEP"), a subsidiary formed to develop, own and manage UtiliCorp's portfolio of EWG, IPP and cogeneration facilities. At that point, the portion of the AEMC proposal for the period June 1, 2001 to May 31, 2004 was assigned to MEP. MPS considered MEP to be an external entity that wished to supply power to MPS and as such we treated MEP in the same manner and subjected its proposal to the same evaluation process as any other proposal submitted to MPS. MPS had treated AEMC as a third party from the beginning of the process and continued to do so.

B. In mid-October, Party D notified MPS that it was undergoing changes in its organizational structure and would no longer be able to honor its proposal. It assigned its proposal to the parent of Party E who was one of the original bidders. Party D was subsequently purchased by another company and ceased to exist.

C. Party C would not accept a contract term of less than ten years and was not comfortable with committing to a fixed price given the increasing price of generation equipment. As a result, it withdrew its proposal in mid September.

D. Party H decided that it needed at least a seven year contract term and was not comfortable owning assets which would be far from its operational base. As a result, it withdrew its proposal in mid November.

E. In early September, 1998, UtiliCorp reached tentative agreement to purchase the excess capacity of Sunflower Electric Cooperative of Hays, KS. This potential resource became a candidate to meet a portion of the capacity needs of MPS in both 2000 and 2001. These agreements were subsequently finalized and executed and filed with and approved by the Kansas State Corporation Commission. Because the Sunflower contracts are now publicly available, I will refer to Sunflower herein by name.

10. As a result of the above events, the remaining power supply options available to MPS were those shown in the following table.

MPS Final Supply Side Options

June 1, 2000 - May 31, 2001	June, 2001 - May 31, 2004
AEMC	Party E
Party G	MEP
Sunflower	Party F
Party B	Party G
	Sunflower (2001 only)

11. Preliminary analysis of the proposals conducted in July and early August, 1998 by the independent engineering and consulting firm of Burns & McDonnell indicated that one of the three following portfolios would offer the lowest cost supply side resources in the 2000 - 2004 time frame:

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A. AEMC (2000 only) and a purchase contract with Party C (2001+)
B. AEMC (2000 only) and a purchase contract with an Exempt Wholesale Generator affiliate of UtiliCorp United Inc. (MEP)
C. AEMC (2000 only) and purchase contracts with Parties D, F, G, and H.

12. The results of the preliminary analysis were presented to the staff of the Missouri Public Service Commission ("MPSC") and the Office of Consumer Council ("OCC") on August 24, 1998. A copy of the August 1998 report by Burns & McDonnell is included in Exhibit 6.

13. As a result of the preliminary evaluation, the proposal from Party B was dropped from active evaluation due to its high capacity price and the fact that it was not a component of any of the low cost portfolios.

14. In mid-August 1998, it became evident that the analysis process was being complicated by the energy price volatility and equipment shortages resulting from the sharp increase in the spot market price of energy in June and July, 1998. As a consequence, in early September 1998, MPS requested that all bidders reconfirm their interest in being a power provider to MPS and to update their proposals.

15. At that time, except for Parties B and G and AEMC, all of the original bidders indicated that they could no longer meet the June 2000 in service date requested in the RFP. Due to the dwindling field of potential suppliers for the capacity needs in the year 2000, analysis efforts for the remainder of September and early October were focused on filling the 265 MW capacity shortfall in the summer of 2000.

16. Thus, for the June 2000 to May 2001 time period, we identified three viable supply options:

A. AEMC (up to 135 MW)
B. Party G (up to 100 MW)
C. Sunflower Electric Cooperative (up to 120 MW)

17. As explained in my affidavit filed in Docket No. ER99-2235-000, we determined that the lowest cost supply option for the June 2000 to May 2001 time period was a combination of supply from AEMC and Sunflower. AEMC filed with FERC its power sales agreement with MPS in Docket No. ER99-2235-000.

18. With respect to the supply options for the period after May 2001, on November 6, 1998 MPS requested that all bidders submit final proposals by November 30, 1998. Of the four possible suppliers, only Party E and MEP chose to update and

resubmit their proposals. Both bidders proposed to construct generation facilities on the MPS system.

19. The Party E proposal was for a seasonal peaking capacity contract with a term of five years. The contract would provide 500 MW to MPS in the months of June through September and 200 MW in the remaining months.

20. The MEP proposal was for a seasonal intermediate capacity contract with a term of four years. The contract would provide 500 MW to MPS in the months of April through September and 200 MW in the remaining months.

21. MPS negotiated with both bidders through December and early January with both bidders being given several opportunities to modify and clarify their respective proposals.

22. Party E submitted its final proposal on January 6, 1999 while MEP submitted its final revision to its proposal on January 12, 1999. On January 14, 1999, Party E was given a final opportunity to improve its proposal and declined to do so.

23. At all times during the contract development process (beginning prior to the issuance of the original RFP and extending through the date of contract execution), I treated MEP as the equivalent of an unaffiliated third party. To ensure that the transaction would not be tainted in any way by the affiliate relationship, whenever MEP modified its proposal, I gave the remaining unaffiliated bidders the opportunity to match the MEP offer. As a result, I believe that the Power Sales Agreement is free from any possibility of affiliate favoritism.

24. The best and final offers from both bidders were modeled in MPS' production costing software and the annual energy supply costs calculated. The annual capacity costs and gas transportation costs were calculated outside the production costing model and were added to the energy supply costs to determine the total annual power supply costs. The assumptions for natural gas commodity and transportation costs as well as market energy price assumptions are contained in Exhibit 7.

25. In addition to evaluating the final proposals from Party E and MEP, MPS recalculated the power supply costs for Case 4, the lowest cost option in the Burns & McDonnell analysis of August 1998. A summary of the results from the base analysis are shown in the following table.

Evaluation Results for June 2001 - May 2005
Supply Side Analysis

	NPV in 2001 $x1,000	
	Without Off System Sales	With Off System Sales
Merchant Energy Partners	467,982	442,894
Party E	467,117	453,535
Case 4	520,660	497,665

27. To test the sensitivity to both natural gas and market energy prices, several different scenarios were created by combining different rates of natural gas price escalation with both low, base and high market energy prices. These scenarios were then analyzed using the MPS production costing model. The results of the sensitivity analysis produced the same results as that obtained in the base case. Summaries of the results for these cases as well as for the base analysis are contained in Exhibit 8.

28. As a final check on its methodology and results, MPS engaged Burns & McDonnell to verify the results of the analysis. The analysis performed by Burns & McDonnell verified the methodology and results obtained by MPS. A copy of the report is included in Exhibit 9.

29. The results of the analysis clearly show that the MEP proposal is the superior supply side resource option available to MPS at this time.

30. In addition, based on my current experience, the pricing in the Power Sales Agreement is significantly below current market prices for the summer 1999 and 2000 periods, and prices can be expected to increase for the summer 2001 period as capacity margins become even tighter.

31. Thus, based on the analysis conducted by both MPS and Burns & McDonnell, the preferred supply side resource plan to meet the capacity and energy needs of MPS in the June 2000 - May 2005 time period is as follows:

   A. Purchase 135 MW from AEMC for the June 2000 - September 2000 time period.

   B. Use 130 MW of the Sunflower contract for MPS needs for the June 2000 to May 2001 time period.

   C. Use 115 MW of the Sunflower contract for MPS needs for the June 2001 to May 2002 time period.

D. Enter into a PPA with MEP which will provide 320 MW during the months of June - September 2001 and provide 500 MW during the months of April to September and 200 MW in the remaining months of the January 2001 - May 2005 time period.

E. Purchase incremental capacity needs through short term contracts.

Dated this 4th day of May, 1999.

Frank W. Becker

SUBSCRIBED AND SWORN TO before me this 4th day of May, 1999.

Catherine L. Thurman
Notary Public for the State of Missouri

Commission Expires:

May 22, 2002

CATHERINE L. THURMAN
Notary Public State of Missouri
Commissioned in [illegible] County
My Commission Expires May 22, 2002

SCHEDULE FAD-29
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UNITED STATES OF AMERICA 88 FERC ☐ 61,027
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
Vicky A. Bailey, William L. Massey,
Linda Breathitt, and Curt HŠbert, Jr.

MEP Pleasant Hill, LLC) Docket No. ER99-2833-000

ORDER ACCEPTING FOR FILING
PROPOSED RATE AGREEMENT FOR SALE OF CAPACITY
AND ENERGY AT MARKET-BASED RATES

(Issued July 2, 1999)

In this order, we accept for filing, without suspension or hearing, the proposed market-based power sales agreement filed by MEP Pleasant Hill, LLC (Applicant), an affiliate of UtiliCorp United Inc. (UtiliCorp).

Background

On May 6, 1999, Applicant and UtiliCorp jointly filed a request for approval of a Unit Power Sales (UPS) Agreement which provides for the sale of capacity and energy to UtiliCorp at market-based rates. 1/

Applicant proposes to construct a 600 MW generating facility in Pleasant Hill, Missouri in order to supply the capacity and energy to UtiliCorp. The proposed UPS rate includes a capacity charge which ranges from $5.70/kW/month to $7.50/kW/month. UtiliCorp will pay for the natural gas used or the equivalent avoided fuel cost to operate the generators, as well as an energy charge of 1.25 mills/kWh and will reimburse the actual transmission charges paid under the appropriate open access tariffs. Applicant requests an effective date of June 1, 2001. 2/

1/ Applicant had requested market-base rate authority for sales to non-affiliates in Docket No. ER99-2858-000. This request was granted by a letter order, issued June 17, 1999. Cleco Trading and Marketing LLC, et al. 87 FERC ☐ 61,311 (1999). Applicant's application for Exempt Wholesale Generator status in Docket No. EG99-141-000 was granted by an order issued under delegation of authority, 87 FERC ☐ 62,337 (1999).

2/ Under the UPS Agreement, either party may terminate the proposed contract if Commission approval is not
(continued...)

Applicant states that the UPS agreement resulted from a competitive bidding process that involved seven other potential suppliers, including Aquila Energy Marketing Corporation (Aquila) -- another UtiliCorp affiliate which recently received approval for a sale to UtiliCorp. Applicant argues that this process is an adequate safeguard to mitigate the potential for self-dealing.

Applicant claims that its market-based rate proposal satisfies the standards set forth in Boston Edison Re: Edgar Electric Energy Company, 55 FERC ☐ 61,382 (1991) (Edgar), where the Commission concluded that, when a subsidiary proposes to sell power under "market-based" rates to another affiliate who serves captive ratepayers, the seller must demonstrate that the buyer will pay no more than a non-affiliate would pay for comparable power (i.e., has not preferred its affiliate without justification). In Edgar, the Commission noted several ways for a utility to show that it has not unduly favored its affiliate: (1) a utility could show that the prices it was paying its affiliate were no higher that those non-affiliated buyers were willing to pay its affiliate; (2) a utility could show that the prices it was paying its affiliate were no higher than those other sellers were able to demand from non-affiliates; or (3) a utility could show that the transaction was the product of a properly structured competitive bidding process. 55 FERC at 62,168-69; Aquila Energy Marketing Corp., 87 FERC ☐ 61,217 at _____, slip op. at 2-3 & n.9 (1999).

Applicant explains that UtiliCorp conducted a competitive solicitation for capacity ranging from 325 MW in 2000 to 650 MW in 2004 and evaluated bids based on seven transaction-specific criteria. 3/ By July 3, 1998, eight parties responded to the solicitation: Aquila, Basin Electric Cooperative (Basin Coop),

2/(...continued)
obtained by July 21, 1999.

3/ The bid evaluation criteria were: (1) the bidder must name a specific resource which would supply the capacity and energy (financially firm proposals were not acceptable); (2) the proposal must offer a buyout option to decrease the capacity commitment at a future date; (3) the proposal should include the cost of transmission to the borders of UtiliCorp's transmission system; (4) the capacity price must be known and fixed (indexed capacity prices were not acceptable); (5) if energy pricing formulas were proposed, UtiliCorp must know the cost of energy prior to submitting its energy schedules; (6) availability of capacity and energy must be guaranteed with reductions in capacity payments for failure to meet guaranteed levels; and (7) the contract term must be for four years or less.

LS Power, LLC. (LS Power), NP Energy, Inc. (NP Energy), NorAm Energy Services, Inc./Houston Industries (Houston), Southern Company Energy Marketing, New Century Energies (New Century), and Carolina Power & Light Company (Carolina P&L). Applicant asserts that UtiliCorp also considered as an eighth option the construction of its own generating unit to be owned by Merchant Energy Partners (MEP), a newly-formed subsidiary of UtiliCorp that will own and manage UtiliCorp's portfolio of generation projects.

According to Applicant, after soliciting a request for final proposals, UtiliCorp received confirmations from Applicant and Houston Industries (Houston). Both bidders proposed to construct generation facilities on the UtiliCorp system. 4/ In the final phase of the bidding, an independent energy consulting firm determined that: Applicant was the only bidder that met each of the seven criteria established by UtiliCorp; the total costs for Applicant's proposal were consistently more favorable than Houston's in all scenarios but one case; and in that one case the costs were virtually the same.

Applicant states that it is requesting waiver of the advance notice requirement of the Commission's regulations in order to ensure that the required regulatory authorizations are in hand before substantial expenses are incurred with respect to the construction of the Pleasant Hill facility.

Notice of Applicant's filing was published in the Federal Register, 64 Fed. Reg. 27,777 (1999), with comments, protests and interventions due on or before May 26, 1999. None was filed.

Discussion

The Commission finds, on the record before it, that Applicant has demonstrated that the rates in the UPS Agreement are no higher than the price UtiliCorp would have paid to purchase power from a nonaffiliate and that the process which resulted in the UPS Agreement satisfies the requirements set forth in Edgar. Accord, Aquila, 87 FERC at ______, slip op. at 3-5.

The Commission finds good cause to grant waiver of Section 35.3(a) of its regulations to allow the agreement to

4/ Applicant states that UtiliCorp decided to consider the initial transaction period (June 2000-May 2001) as a separate transaction, and decided to enter into a four month agreement with Aquila and Sunflower Electric Cooperative (Sunflower), to meet part of its near-term needs. The filing at issue here reflects UtiliCorp's remaining long term purchase need.

be filed more than 120 days in advance of the proposed effective date. Accordingly, the Commission will accept the UPS Agreement for filing and allow it to go into effect, without suspension or hearing, on June 1, 2001.

The Commission orders:

(A) Waiver of section 35.3(a) of the regulations is hereby granted.

(B) The agreement submitted by MEP Pleasant Hill, LLC is hereby accepted for filing, without suspension or hearing, to become effective on June 1, 2001.

(C) MEP Pleasant Hill, LLC is hereby informed of the rate schedule designations shown on the attachment to this order.

By the Commission.

(S E A L)

David P. Boergers,
Secretary.

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Attachment
MEP Pleasant Hill, LLC
Docket No. ER99-2833-000
Rate Schedule Designations

Designations
Description

Service Agreement No. 1
Unit Power Sales with
under FERC Electric Tariff,
UtiliCorp United, Inc.
Original Volume No. 1