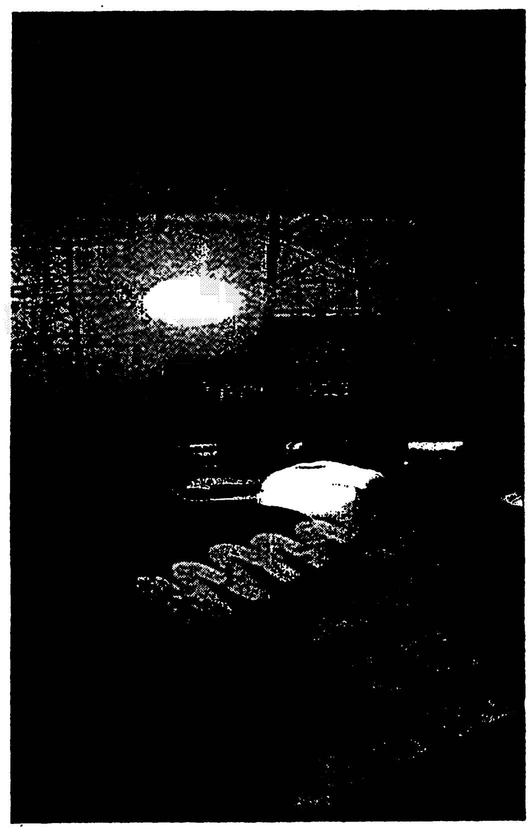
UTILICORP UNITED INC.

MISSOURI PUBLIC SERVICE

1998-2003
PRELIMINARY
ENERGY SUPPLY PLAN

August 24, 1998



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1. EXECUTIVE SUMMARY

1.1 Objectives

UtiliCorp's regulated electric operations for its Missouri Public Service division (MPS) face a 250+ MW shortfall of capacity and associated energy in the year 2000. This shortfall will grow to over 480 MW by the summer of 2003. The capacity shortfall is principally driven by the expiration of three purchase power contracts which total 295 MW in 1999 and the expiration of leases on 272 MW of peaking capacity.

The principle objective of the 1998-2003 Missouri Energy Supply Plan is the acquisition of incremental capacity and associated energy which will:

- Provide a cost effective energy supply to MPS electric customers in the short term; and,
- Assure that supply resources acquired have the ability to successfully compete in future deregulated energy supply markets.

1.2 Planning Process

The MPS energy supply analysis began with market and resource need analysis which included:

- Load Forecast, 1998-2017
- National and Regional Capacity & Energy Price Forecasts
- MPS Supply Requirements
- MPS Supply Resources

Based on the future supply needs of MPS, three supply options were considered:

- Purchase Power Contracts
- Simple Cycle Combustion Turbine Peaking Units
- Combined Cycle Combustion Turbine Units

As an initial step in meeting the MPS capacity and energy needs, a Request for Proposals (RFP) was issued on May 22, 1998 which solicited proposals to supply MPS' incremental capacity needs in the years 2000 - 2003. Proposals were received on July 3, 1998.

In conjunction with the issuance of the RFP, projections of the market clearing prices for MPS and the adjoining regional markets were prepared along with ownership cost estimates for the following resources:

- 1x100 MW Simple Cycle Combustion Turbine Unit
- 1x165 MW Simple Cycle Combustion Turbine Unit

- 2x165 MW Simple Cycle Combustion Turbine Units
- 1x250 MW Combined Cycle Unit
- 2x250 MW Combined Cycle Units

The proposals received in response to the RFP were evaluated by Burns & McDonnell and compared to the cost to supply energy from the most competitive of the five UCU owned resource options listed above. A draft report outlining the results of the analysis conducted by Burns & McDonnell is attached as Appendix A.

The result of the above analysis is a preliminary supply plan which will meet all of MPS' capacity and energy needs through 2003 and a major portion of its needs thereafter. Conclusions and a recommended action plan are contained in sections 1.4 and 1.5 respectively.

1.3 Assumptions

Key data assumptions utilized in the analysis are shown in the following table.

Table 1.3-1: Data Assumptions

Topic	Assumptions
Inflation Rates (1998-2013)	CPI: 2.5% Construction Costs: 2.5% O&M Costs: 2.5%
Cost of Capital	Debt: 50% @ 7.0% Equity: 50% @ 11% IRR Discount Rate: 10%
Fuel Price Escalation (1994-2013) - Real 2.50%	Natural Gas: Real + 0.50% PRB Coal: Real - 0.50% Hanna Coal: Real - 0.50%
Reserve Margin	13.0% Reserve Margin
Financial Data	Federal Tax Rate - 35% State Eff. Tax Rate - 5% (MO)

1.4 Conclusions

Based on the 1998-2003 supply-side analysis, the least-cost plan for MPS consists of executing short term purchase contracts to meet MPS capacity needs through the year 2000, and the construction of a gas-fired 500 MW combined cycle unit to meet all of MPS' capacity needs in the 2001-2003 time frame and a majority of its needs thereafter.

The above supply plan provides the least cost means to meet the MPS capacity and energy needs even though MPS' has a low annual load factor of <50% and an abundant supply of low-cost energy supplied by its existing resource base which is 64% coal-fired base load generating capacity.

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The ability of combined cycle units to compete in the regional energy market place enables these resources to provide sufficient revenue to offset their higher capital cost.

1.5 Recommended Action Plan

As a result of the analysis outlined in this report, it is recommended that UCU:

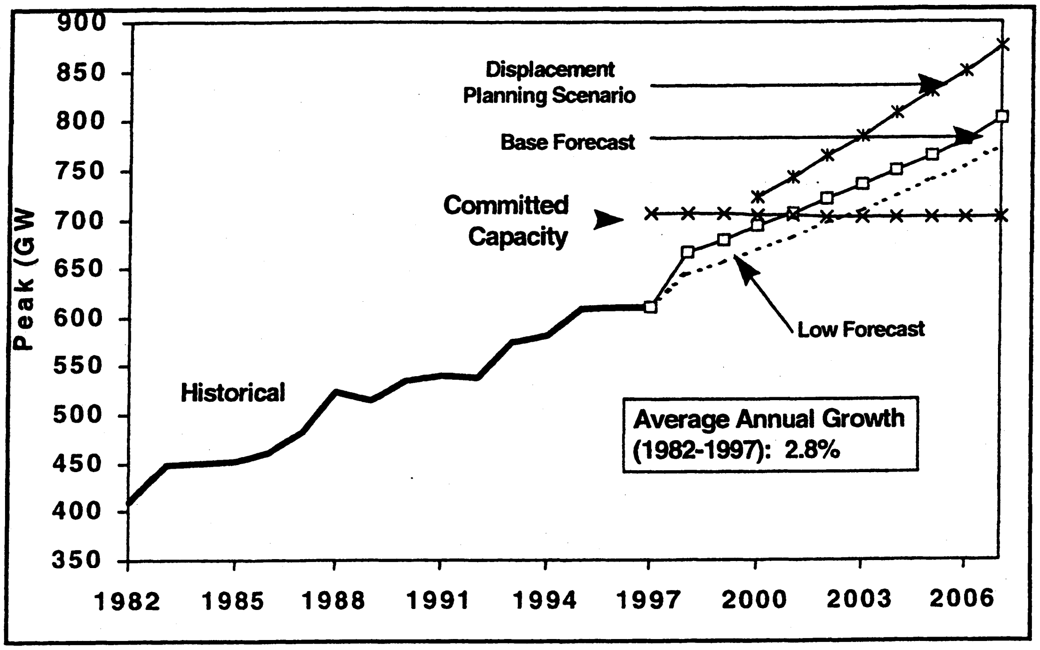
- Negotiate extension of the existing lease agreements on the Greenwood combustion turbines.
- Secure short term capacity to meet MPS' capacity needs thru 2000.
- Pursue the construction of a 500 MW combined cycle unit proposed with an in service date of June 1, 2001.

2. RESOURCE NEED ANALYSIS

2.1 National and Regional Forecasts

United States capacity supply needs in the 2001 - 2007 time frame are projected to be 100 - 175 GW in excess of existing and committed capacity. If displacement of inefficient fossil and nuclear generation is considered the shortfall increases an additional 40-50 GW. Chart 2.1-1 presents this data in graphical form.

Chart 2.1-1: U.S Projected Capacity Short Fall



On a national basis, U.S. and Canadian capacity reserve margins have been decreasing for the past fifteen years. In the U.S., reserve margins will fall below ten percent around turn of the century. Chart 2.1-2 shows the projected reserve margins for both the U.S. and Canada. Note the dramatic impact of premature nuclear retirements on the reserve margins of both the U.S. and Canada.

On a regional basis, the decline in the reserve margin becomes more dramatic in many regions of the U.S. Reserve margins are projected to fall below zero by 2002 in ECAR, MAPP, MAIN and portions of SERC. Table 2.1-3 presents the reserve margin for all NERC regions and sub-regions of the U.S.

Chart 2.1-2: Projected U.S. & Canadian Reserve Margins

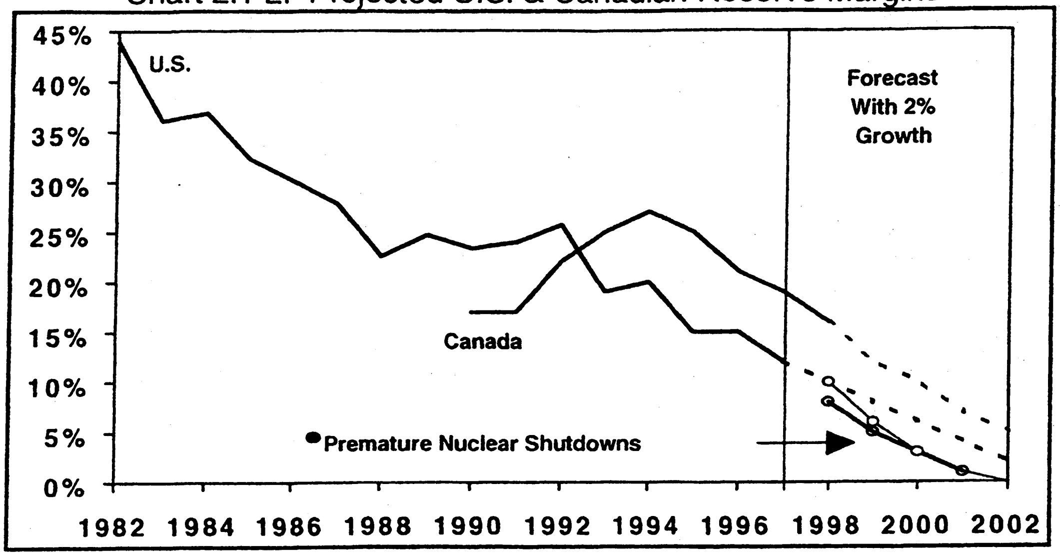


Table 2.1-3: Projected U.S. Regional Reserve Margins

Region	Reserve Margin (%)			
	1995	1998	2002	2002 NS*
ECAR	11.5	8.5E	-2.6	-3.2
ERCOT	18.5	14.8E	3.4	3.4**
MACC	15.4	14.0	2.7	1.6
MAIN	11.1	6.8	-4.3	-12.1
MAPP	11.3	4.1E	-3.6	-13.4
NPCC	30.0	24.0	11.7	2.7**
- NY	30.8	23.3	12.0	6.2**
- NEPOOL	28.8	24.0	11.4	-7.5**
SERC	10.3	8.2E		
- Florida	9.0	7.1E	3.1	3.1**
- Southern	9.9	0.5E	-11.0	-11.0
- TVA	0.7	5.6	-3.1	-3.1
- VACAR	21.3	17.7E	6.6	6.6
SPP	14.5	13.0	2.0	1.0
WSCC	-	-	-	-
- Northwest	17.6	11.1E	3.5	3.5
- California	14.8	13.9E	3.2	3.2**
- AZ/NM	10.7	14.4E	3.5	3.5
- Rockies	22.7	22.0	10.6	10.6

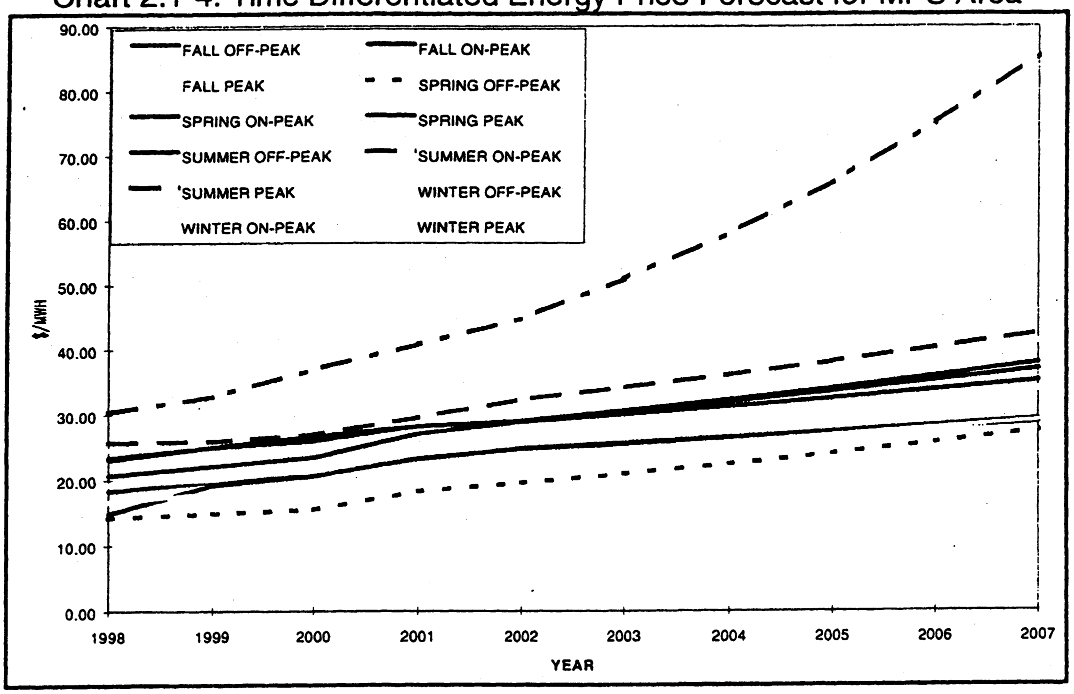
*With Premature Nuclear Shutdowns (NS)
**Region also includes inefficient Fossil capacity with potential for displacement.

Projections of the regional marginal energy price are key to the determination of the profitability of generation resources in a competitive marketplace. To obtain an unbiased forecast of marginal energy prices, the firm of Hill & Associates was retained in December, 1997 to prepare a forecast for the years 1998 - 2017. Key financial and fuel price assumptions for the forecast are shown in Table 1.3-1 in section 1.3. The other major driver in the forecast is the timing of additional generation resources. For the purpose of this forecast, additional generation capacity was added when the average annual marginal energy price in a region reached $26.00/MWh in 1997 dollars. In order to obtain more accurate pricing of seasonal and time of day energy cost, each year was divided into four seasons (summer, fall, winter and spring) and each season divided into three time periods:

Off peak	Midnight to 8AM
On Peak	8AM - Midnight, except 3PM - 6PM
Peak	3PM - 6PM

Chart 2.1-4 shows the projected marginal energy cost for the MPS area for the years 1998 - 2007. Projected prices for the northern region of the SPP are similar.

Chart 2.1-4: Time Differentiated Energy Price Forecast for MPS Area



2.2 MPS Capacity Needs

Table 2.2-2 provides a summary of the MPS loads and resources forecast for MPS over the 1998-2004 planning horizon. The forecast assumes that MPS will be successful in retaining the peaking capacity associated with the leased units. New capacity of 256 MW will be required by 2001 to meet MPS' projected capacity needs. This need will grow to 480 MW by the summer of 2003.

Table 2.2-1: MPS Loads & Resource Summary

Year>>	1998	1999	2000	2001	2002	2003	2004
MPS Demand Forecast in MW							
Base Forecast	1,167	1,203	1,237	1,268	1,297	1,331	1,369
Less Interruptables	(5)	(5)	(5)	(5)	(5)	(5)	(5)
Net	1,162	1,198	1,232	1,263	1,292	1,326	1,364
MPS Generation Capacity in MW	1,045	1,045	1,045	1,045	1,045	1,045	1,045
MPS Purchased Capacity in MW	345	395	115	-	-	-	-
MPS Total Capacity in MW	1,390	1,440	1,160	1,045	1,045	1,045	1,045
Capacity Margin in MW	228	242	(72)	(218)	(247)	(281)	(319)
Required Capacity Margin in MW	174	179	184	189	193	198	204
Capacity Surplus (Deficit)	54	63	(256)	(407)	(440)	(479)	(523)

3. EXISTING SUPPLY RESOURCES

3.1 Generation

During 1997, UtiliCorp's Missouri Public Service (MPS) electric operations consisted of 14 generating units with an accredited capacity of 1,045 MW. Actual system coincident peak load was 1,131 MW in July 1997. 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 in 1997. MPS' single largest generating unit is the coal-fired Sibley Unit 3, which has a net rated capacity of 396 MW. MPS' other coal-fired resource is its 176 MW ownership in the Jeffery Energy Center. MPS also owns 105 MW of peaking capacity and leases an additional 267 MW of peaking capacity.

3.2 Purchased Power Contracts

MPS purchases capacity and energy through purchase power contracts with three 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 Union Electric (UE). Capacity and energy are purchased under an agreement executed in 1987. The UE purchase contract expires May 31, 2001, at which time the contract amount totals 115 MW.

The third 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.

The following table summarizes the purchased capacity amounts from the AEC, UE and KCPL contracts available in the years 1997 - 2000:

Table 3.2-1: MPS Purchase Power Contracts

Year (June 1)	AEC Contract (MW)	UE Contract (MW)	KCPL Contract (MW)	Total (MW)
1997	150	115	30	295
1998	170	115	60	345
1999	190	115	90	395
2000	--	115	--	115

3.3 Power Plant Improvements

The supply-side resource analysis included identification of specific re-powering and equipment modification options for existing MPS generating resources. These power plant improvement options have been identified based on inquiries to equipment manufacturers. The cost estimates for these options are too preliminary to quantitatively analyze them in the supply-side resource analysis at this time. It should be noted that the total of potential capacity increase of 54 MW represents only 10 percent of MPS' incremental capacity need through 2001.

A. New High Flow Inlet Guide Vanes - Greenwood (8 MWs)

Combustion turbine inlet guide vanes (IGVs) act as air flow limiters during startup and low load operations. This necessary feature for low load situations can penalize full load capacity by restricting 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 and with it higher capacity. These potential modifications at the Greenwood Plant have the advantages of not impacting O&M, emissions rates, or operating procedures.

B. Water Injection - Greenwood (12 MWs)

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 at the Greenwood Plant 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.

C. Upgrade Jet Engines - KCI Airport (4 MWs)

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 to the KCI jet engines include no impacts to O&M, operating procedures, or emissions rates. Upgrades during 1995 totaling 10 MW to the existing KCI Units 1 and 2 are included in the existing resources.

D. Boiler/Turbine Upgrade - Sibley (30 MWs)

The turbine manufacturer, Westinghouse, and the boiler manufacturer, Babcock & Wilcox, have indicated that additional capacity can be achieved through modifications to their equipment and some plant auxiliaries. Evaluation will include impact on fuel blend, emission rates, heat rate and total installed cost.

3.4 Combustion Turbine Lease Renewal

MPS currently leases the majority of its combustion turbine capacity. The following table shows the unit, capacity and current lease termination date for these units.

Table 3.4-1 Leased Combustion Turbine Data

Unit Name	Capacity (MW)	Lease Termination
Nevada	20	June, 1999
Greenwood #1	62	June, 2000
Greenwood #2	62	June, 2000
Greenwood #3	62	June, 2002
Greenwood #4	61	June, 2004

The following action plan has been initiated to determine whether UCU 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 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 which 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. FUTURE SUPPLY OPTIONS

4.1 Introduction

As mentioned in section 1.2, two types of future UCU-owned supply resources were evaluated. This section provides technology descriptions for each of these resources. Cost data and operating characteristics are presented for the UCU-owned supply resources which are shown in Table 4.1-1.

Table 4.1-1: UCU Owned Supply-Side Resources

Description	Service Class	Construction Cost in $/kw	Ownership Cost in $/kw-mo. @ 11% IRR
1x100 MW CT	Peaking	$294	~$4.25
1x165 MW CT	Peaking	$263	~$4.00
2x165 MW CT	Peaking	$259	~$4.00
1x242 MW CC,	Intermediate	$425	~$6.40
2x242 MW CC	Intermediate	$361	~$5.50

4.2 Peak Load Supply Resources

Combustion Turbine

Combustion turbines consist of an air compressor, a combustion chamber, and an expansion turbine. Gaseous or liquid fuels are burned under pressure in the combustion chamber, producing hot gases that pass through an expansion turbine, driving an air compressor and an electrical generator. This arrangement, with no recovery of the energy contained in the high temperature exhaust gases, is referred to as a simple cycle.

The combustion turbine technology is a mature technology which has quick starting capabilities, ease of siting, low capital costs, relatively short construction time, and lower air emissions than coal-fired resources. However, the units burn natural gas or oil which are relatively costly fuels subject to substantial price fluctuations. Combustion turbines thus have high operating costs at higher capacity factors.

4.3 Base & Intermediate Load Supply Resources

Combined Cycle

A combined cycle facility includes a combustion turbine, a heat recovery steam generator (HRSG) and a conventional steam turbine. Exhaust gases from the combustion turbine are used to generate steam in the HRSG, which powers the steam turbine. Combined cycle is a mature technology with numerous facilities operating throughout the United States.

The combined cycle has greater efficiency than the combustion turbine, has a short construction time, can be constructed in stages, and has lower air emission rates than conventional steam turbine generation units. Combined cycle units can be designed to burn a variety of fuels including natural gas, syngas, biogas and fuel oil.

The current combined cycle technology has demonstrated NOx emissions as low as 9 PPM without SCR or water injection and the thermal cycle efficiency is approaching 60 percent (LHV).

With the addition and expansion of digital based control systems combined cycle plants can deliver an average annual availability greater than 98 percent while providing daily cycling capability.

To provide the maximum amount of operational and marketing flexibility, the combined cycle plant could be constructed in stages with the simple cycle combustion turbine being constructed first followed by the HRSG and steam turbine. Operational flexibility would be maximized with the addition of bypass dampers in the combustion turbine exhaust to allow operation of the combustion turbine in simple cycle mode.

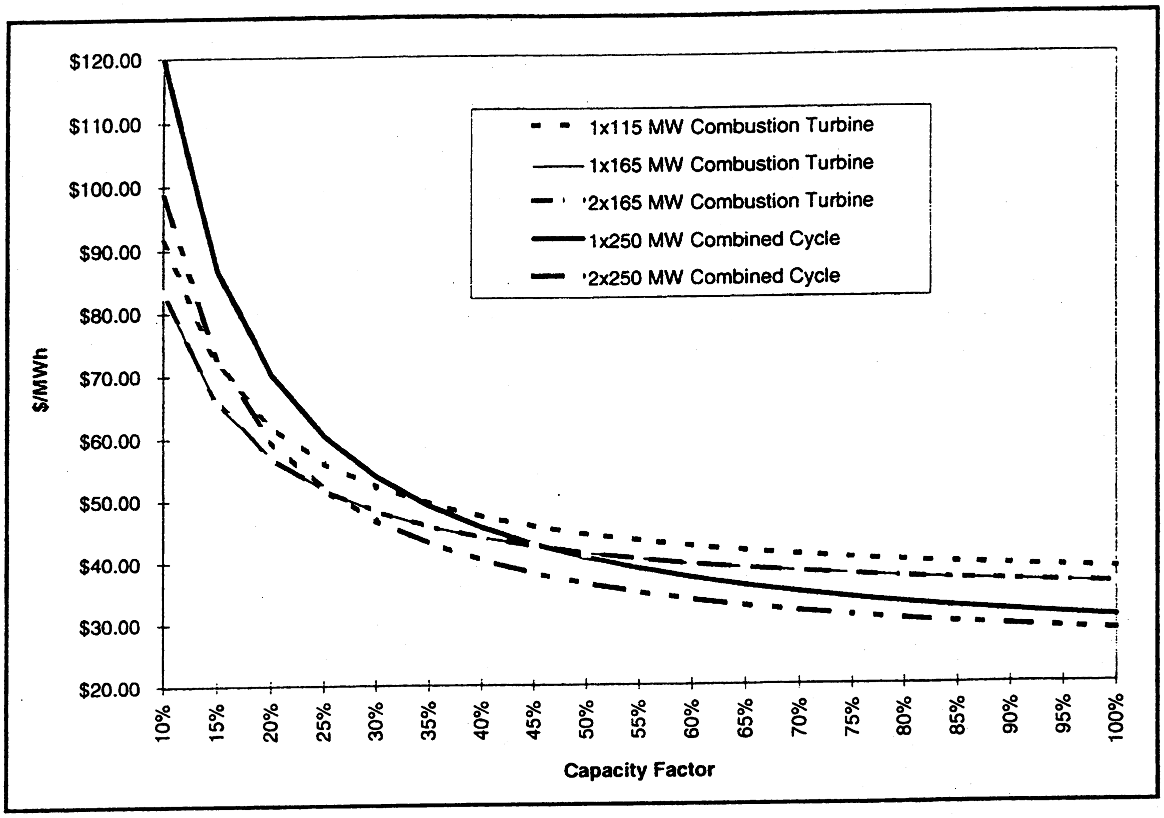
4.4 Resource Analysis

Analysis of the competitive potential of UCU owned supply resources involved the use of screening curves. Screening curves representing each technology option are placed on a common chart. Each option is represented by a line that gives the total "all in" production cost in $/MWh as a function of capacity factor. The intersection points where the cost of one option is equal to the cost of an alternative represent the capacity factor at which the options are equal in cost. At any given capacity factor, the option with the lowest cost will be represented by the lowest curve on the chart. The screening curves for the five UCU owned supply options are shown in Chart 4.4-1 on the following page.

These screening curves enable the comparison of costs for each resource across the range of capacity factors at which the resource can operate. This approach clearly demonstrates the least-cost resource options at various capacity factors; indicates the capacity factor range over which the alternative has the least costs and reveals if a resource is least cost at any capacity factor.

The information shown in Chart 4.4-1 was used to compare the total cost of the various resource types across the spectrum of annual capacity factors. As can be seen in Chart 4.4-1, the "2x250" combined cycle option has the lowest operating cost at annual load factors greater than 25%. This is due to economies of scale of large units and the efficiency advantage of combined cycle units when compared to simple cycle units.

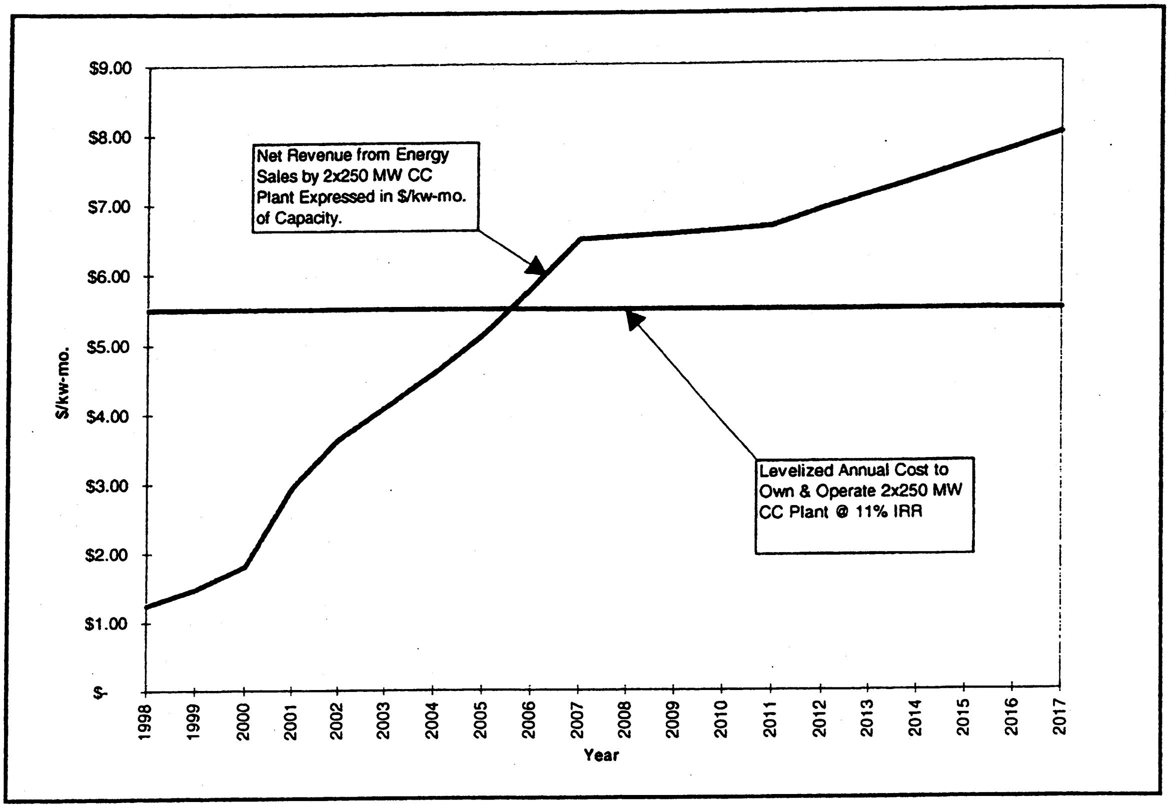
Chart 4.4-1: "All In" Production Cost vs. Load Factor for five Supply Alternatives



To determine whether a large combined cycle unit would be able to compete in a deregulated marketplace, the annual ownership cost was compared to the annual revenue stream that could be expected from selling the energy output into the regional market at the projected market clearing price. Chart 4.4-2 compares the levelized annual ownership cost in $/kw-mo. of a 2x250 MW combined cycle unit to the annual revenue stream expressed as expected as a monthly capacity payment. As can be seen, the "2x250MW" unit becomes competitive in 2006.

Based on the analysis described here, UCU chose to evaluate the "2x250" MW combined cycle unit against the proposals received in response to the RFP issued on May 22, 1998.

Table 4.4-2: Levelized Ownership Cost vs. Energy Revenue



5. SUPPLY RESOURCE ANALYSIS

The analysis of the proposals received in response to the RFP issued on May 22, 1998 was conducted by Burns & McDonnell. Their preliminary report is attached as Appendix A.

Proposals were received from seven different firms. Only two of the proposals were for capacity and energy from existing resources. The remaining proposals were for capacity and energy from resources now under construction or from resources which would be constructed if the bidder was chosen in the evaluation process.

In summary, the results of the analysis indicate that UCU's proposal to construct a "2x250" MW combined cycle unit provides MPS the lowest cost energy supply. The total energy supply cost is strongly influenced by the incremental revenue resulting from off-system sales of energy produced by the proposed combined cycle unit.

Burns & McDonnell 100 1898 • 1998

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

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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		June, 2000 to May, 2001	June, 2001 to May, 2002	June, 2002 to May, 2003	June, 2003 to May, 2004
		Evaluation Period			
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
Southern	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

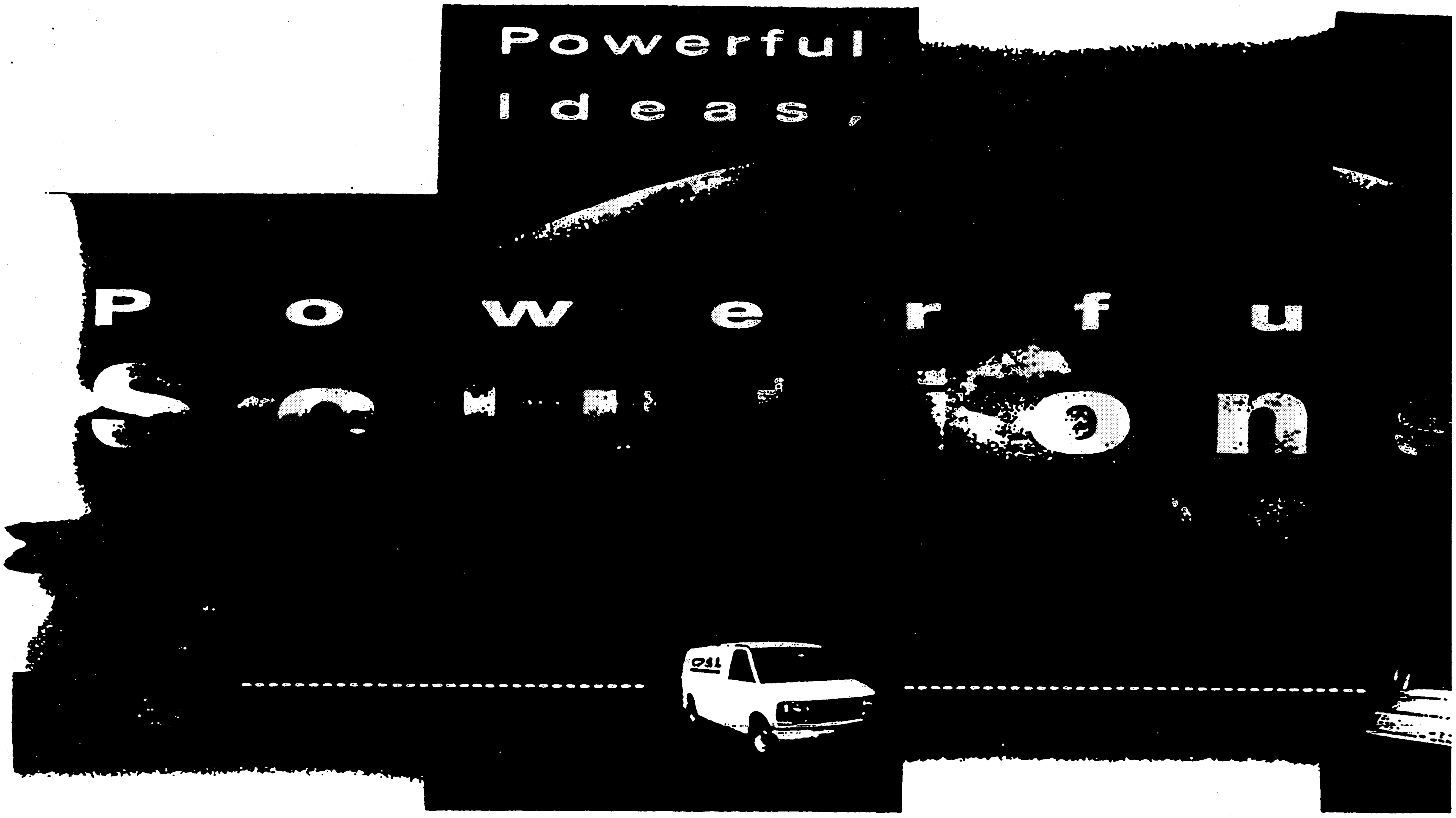
Case	Contract	Capacity MW	Energy MWh	Cost $	Total Purchases $	Total Sales $	Total Generations Cost $	Total Expense $	% Above Least Expensive Case	$ Above Least Expensive Case
Case 1					$ 389,912,026	-$244,101,124	$ 270,450,846	$ 416,261,748	6.4%	$ 25,094,747
	LS Power Unit 1 (Online 2001)	270	5,503,419	$ 172,351,627						
	LS Power Unit 2 (Online 2001)	270	5,215,847	$ 166,023,918						
	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	348,547	$ 16,082,792						
	(Peaking Capacity)	25	10,849	$ 1,720,933						
	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 (Parital 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	128	$ 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 (Parital 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	$ 35,079,240						
	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 (Parital Requirement)	75/100	2,735,959	$ 97,822,664						
	(Peaking Capacity)	25	10,904	$ 1,726,163						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,609,397	-$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	19,268	$ 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 (Parital 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	269,141	$ 35,000,521						
	Southern	100	2,095,140	$ 60,891,338						
	NP Energy	100	6,746	$ 18,593,373						
	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 (Parital 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	18,118	$ 18,964,500						
	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 (Parital 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	168	$ 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	$ 4,816,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Parital Requirement)	75/100	2,735,959	$ 97,822,664						
	(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	1,475,468	$ 71,142,954						
	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	2,736,170	$ 97,825,464						
	(Peaking Capacity)	25	10,823	$ 1,721,288						
	Unit-Contingent Purchase	55	12,706	$ 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	$ 120,708,610					
	Utilicorp Unit 2 (Online 2001)	250	1,379,094	$ 77,768,906					
	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	$ 71,756,138					
	(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	$ 30,595,167					
	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 (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					
	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	$ 71,834,585					
	(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



Proposal to UtiliCorp Energy Group in response to Request for Proposal on behalf of Missouri Public Service Company

Submitted by: Carolina Power & Light Company

July 2, 1998

CP&L

CP&L

July 2, 1998

~~Carolina Power & Light Company~~
PO Box 1551
411 Fayetteville Street Mall
Raleigh NC 27602

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

Re: CP&L's Proposal Submittal in regard to Utilicorp Energy Groups's RFP

Dear Mr. Harris:

To help meet Missouri Public Service's growing business needs for creative power supply solutions, CP&L is pleased to respond to UtiliCorp Energy Group's May 22, 1998 RFP. Enclosed you will find one original and three copies of our proposal for your consideration.

The consummation of the proposals provided herein is subject to the execution of a mutually agreeable contract and the approval of our respective management. By accepting these proposals for review, Utilicorp Energy Group agrees that these proposals in their entirety shall remain confidential, except as required to be disclosed by law and only to the extent required by law. CP&L shall be notified prior to any release of information contained in these proposals. This offer will expire on September 1, 1998. Please let me know if these conditions are not acceptable to Utilicorp Energy Group.

We appreciate the opportunity to provide these proposals. I look forward to hearing from you regarding your evaluation of our proposals.

Yours truly

Karla Haislip

Karla Haislip
Bulk Power Marketer

enclosures (original and 3 copies)

Proposal Overview

Carolina Power & Light Company (CP&L) is committed to becoming a power supplier for Missouri Public Service. We plan to be your energy supplier of choice by offering a competitive, reliable solution to your power supply needs.

CP&L is an investor owned utility, providing electric power to approximately 1.1 million customers in eastern and western North Carolina and central South Carolina. Founded in 1908 and headquartered in Raleigh, North Carolina, the company has over 10,000 MW of Contributing Resources. Our generating facilities represent a flexible mix of fossil, nuclear and hydroelectric resources.

CP&L is pleased to respond to Missouri Public Service's power supply needs described in its May 22, 1998 request for proposal (RFP) by offering the following proposal, that offers a unique solution for your consideration for a four year term.

We have designed our proposal to provide Missouri Public Service with a power supply option that can be used to shape a solution that best fits Missouri Public Service's needs. A closer look at this proposal will reveal a solution that offers competitive indexed energy pricing.

CP&L is committed to becoming a power supplier for Missouri Public Service. We appreciate the recent opportunity to provide this proposal. Since this is a preliminary introduction to Missouri Public Service, we would value the opportunity to meet and discuss this proposal in further detail as well as your other business needs for the future. We look forward to working with you to finalize the details of this or any other solution that will meet your power supply needs.

CP&L's Proposal

Capacity Components and Term: This proposal is for peaking capacity. Amount equal to 150 MW's. Term of four (4) years beginning June1, 2000 and ending May 31, 2004.

Energy Price: (Pricing at Missouri Public Service's Border) The energy price would be based on a mutually agreed upon gas index at the facility and will include transportation, variable O&M fees, and a heat rate assumption of 12,000 BTU/kWh.

Firmness: This sale is a unit power sale, with a 5% effective forced outage rate. The effective forced outage rate is measured based on peaking availability. Terms and conditions for performance based compensation for exceeding the 5% to be negotiated.

Energy Scheduling: Missouri Public Service provides to CP&L daily, a rolling seven-day estimate of hourly energy usage by 8:00 a.m. The actual energy schedule is fully dispatchable, meaning that Missouri Public Service may make same-day adjustments within reasonable limits with one-hour notice.

Transmission and Ancillary Services Pricing: CP&L will purchase these services necessary and will deliver capacity and energy to Missouri Public Service's border. The price for these services is included in our proposal.

Delivery Point: The delivery point shall be at the interconnection between the facility and Missouri Public Service's transmission system. CP&L reserves the right to provide energy at alternate delivery points into the Missouri Public Service system.

Siting: Missouri Public Service will assist in site location and development. CP&L will have the right to deliver excess capacity and energy to Missouri Public Service's interconnections and will reimburse Missouri Public Service for transmission losses to the interconnections. CP&L has made certain assumptions concerning siting, transmission and fuel supply. Additional information would allow CP&L to refine proposal.

Capacity Pricing

Years	2000	2001	2002	2003	2004
Demand Charges ($/MW-month)	$4690	$4810	$4930	$5050	$5180

CP&L

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

Tel 281 584 3000
800 334 2726

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

a Vastar partnership

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.

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.

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.

NEW CENTURY ENERGIES

PO Box 1261
Amarillo, Texas 79170-0001

PUBLIC SERVICE

SOUTHWESTERN PUBLIC SERVICE COMPANY

CHEYENNE LIGHT FUEL & POWER

July 3, 1998

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

RE: Request for Proposals dated May 22, 1998.
Purchase of Resource Specific Capacity and Energy for the period June 1, 2000 through May 31, 2004.

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 in the following options, 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.

OPTION A - PARTIAL REQUIRMENT POWER SERVICE, WITH PEAKING POWER SERVICE

The term "Partial Requirements Power Service, with Peaking 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, 2001 through May 31, 2004.

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

TABLE 1	
Period	**Capacity**
June 1, 2000 - May 31, 2001	25 or 75 MW
June 1, 2001 - May 31, 2002	50 or 100 MW
June 1, 2002 - May 31, 2003	50 or 100 MW
June 1, 2003 - May 31, 2004	50 or 100 MW

Peaking Power Capacity Amounts: As per the following Table 2 (and to be taken in addition to the Partial Requirements Capacity amounts):

TABLE 2	
Period	**Capacity**
June 1, 2000 - September 30, 2000	25 MW

Billing and Scheduling Charge: $320.00 per month.

Partial Requirements Capacity Charge: The price of the Partial Requirements Power Service Capacity is as shown in the Table 3:

TABLE 3	
Period	**Capacity**
June 1, 2000 - May 31, 2001	$ 5,200/MW - Month
June 1, 2001 - May 31, 2002	$ 5,200/MW - Month
June 1, 2002 - May 31, 2003	$ 5,400/MW - Month
June 1, 2003 - May 31, 2004	$ 5,400/MW - Month

$7641/MW-mont.
2% Esc.

Peaking Power Capacity Charge: The price of the Peaking Power Capacity is as shown in Table 4:

TABLE 4	
Period	**Capacity Charge**
June 1, 2000 - September 30, 2000	$ 9,000/MW - Month

$1144/MW-mo.
0 % Esc

Partial Requirements Energy Price: The price of energy delivered to UEG shall be $1.00/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 5 shows an estimate of the ~~anticipated Wholesale FCA for the calendar years shown.~~

TABLE 5	
Year	**Projected Wholesale FCA Factor ($/MWh)**
2000	19.00
2001	18.17
2002	17.79
2003	15.90
2004	16.38

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.

Peaking Power Energy Price: The energy price for all energy produced for UEG from Peaking Power Service shall be $4.00/MWh plus either of the following of the pricing methods:

1. The price of natural gas multiplied by 1.05 (New Mexico Gross Receipts Tax) and multiplied by the assigned heat rate of 11.5 MMBtu/MWh. The price of natural gas shall be the greater of the Gas Daily Index plus $0.30 or Gas Daily Index times 1.15. Where the Gas Daily Index is the price stated in dollars per MMBtu for the daily midpoint of Northern (Mids 1 - 6) as published on the day of delivery in Pasha Publication's Gas Daily under the table titled "Daily Price Survey".
2. UEG can be responsible for the procurement and delivery of all natural gas to a suitable delivery point for all the electric energy requested by UEG.

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 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.

Peaking Power Energy Scheduling: The energy shall be scheduled by notifying SPS by 8:30am for Peaking Power energy to be delivered for the following day unless mutually agreed upon otherwise by both parties. Should UEG need to schedule this 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 25 MW for eight hours. 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 Partial Requirements 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 6:

TABLE 6

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	100 MW	$ 2,700/MW – Month
June 2002 through May 2003	1/1/2002 - 2/28/2002	100 MW	$ 4,050/MW – Month
June 2003 through May 2004	10/1/2002 - 12/31/2002	100 MW	$ 2,700/MW – Month
June 2003 through May 2004	1/1/2003 - 2/28/2003	100 MW	$ 4,050/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. 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 6.
- 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.

OPTION B - INTERRUPTIBLE POWER SERVICE + system contingent

The term "Interruptible Power Service" shall mean that quantity of electric power and associated energy that SPS will make continuously available to UEG, except at times of system contingencies as determined by SPS at its discretion at which time it may be curtailed.

Contract Period: The period from June 1 2000, through May 31, 2004.

Capacity Amounts: Up to the amounts shown in Table 7, in 50 MW increments and a minimum of 50 MW for all Contract Years:

Table 7

Contract Year	Months & Capacity Amount	Months & Capacity Amount
6/1/2000 – 5/31/2001	June – September: 100 MW	October – May: 75 MW
6/1/2001 – 5/31/2002	June – September: 100 MW	October – May: 150 MW
6/1/2002 – 5/31/2003	June – September: 100 MW	October – May: 150 MW
6/1/2003 – 5/31/2004	June – September: 100 MW	October – May: 150 MW

In the three contract years, from June 1, 2001 through May 31, 2004, UEG may only purchase capacity during the months of October through May in amounts no less than what was purchased for June through September of the same Contract Year.

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.	

$2441/MW

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.

Jack L. Farley, Jr.
Vice President,

NP Energy Inc.
3650 National City Tower
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

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

LS POWER, LLC

101 Southhall Lane, Suite 400
Maitland, Florida 32751
(407) 667-4848 Fax (407) 667-4849

Robert L. Brooks
Vice President, Marketing

July 2, 1998

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

Dear Mr. Harris:

In response to UtiliCorp Energy Group's request for proposal on behalf of Missouri Public Service, LS Power is pleased to provide three copies of the enclosed proposal. This proposal is confidential and we request that it be treated accordingly.

We look forward to your favorable evaluation of our proposal and should you have any questions, please do not hesitate to contact me.

Sincerely,

R. L. Brooks

Robert L. Brooks

PROPOSAL FOR POWER SUPPLY
FROM LS POWER, LLC
TO UTILICORP ENERGY GROUP
ON BEHALF OF MISSOURI PUBLIC SERVICE
JULY 2, 1998

EXECUTIVE SUMMARY

LS Power, LLC and its affiliates ("LS Power") is a leader in the development of greenfield generation facilities serving the United States market. Within the past several years LS Power completed construction of three projects comprising approximately 700 megawatts and has commenced construction on another two projects representing 716 megawatts of capacity. Additionally, LS Power has another 800 megawatts committed pursuant to power purchase agreements, with numerous other projects under development. Given the transition in the electric utility industry, this accomplishment serves as a testament to LS Power's commitment to the United States market and its ability to structure highly competitive, flexible and innovative business arrangements with its customers.

Of particular relevance to this proposal is the long standing working relationship that has been established between UtiliCorp and LS Power. For example, Aquila Energy Marketing Corporation is under a long term contract to supply gas to the Whitewater, Wisconsin and Cottage Grove, Minnesota Projects developed by LS Power. Aquila will also be supplying gas to the Mustang Project located in Denver City, Texas. Most recently, Aquila Power Corporation and UtiliCorp United, Inc. entered into a power purchase agreement with LSP Energy Limited Partnership for supply from our Batesville, Mississippi Project.

With this proposal, LS Power, LLC ("LSP") is offering to provide Missouri Public Service ("MPS") the output of either one or two (at MPS's choice) combined cycle trains under the terms of a tolling arrangement. The nominal output of each train will be 270 MW. The units will be located at a site within MPS's service territory, with the specific location to be determined with input from MPS. Based upon execution of a letter of intent for a power purchase agreement by August 1, 1998 and execution of a power purchase agreement by September 1, 1998, the delivery start date will be June 1, 2001. LSP will be responsible for developing, financing, constructing, operating and maintaining the project.

LSP views this proposal as a starting point to an interactive process between MPS and LSP to refine the specifics of a power purchase arrangement that satisfies the respective objectives of each party. During the evaluation process, LSP strongly encourages MPS to provide feedback to LSP to facilitate such an interactive process, and in turn, LSP commits to work with MPS to structure an arrangement that is mutually beneficial.

CONTRACT QUANTITY

The Contract Quantity will be the sum of the Standard Capacity and the Supplemental Capacity. "Standard Capacity" is the maximum output of the unit without the use of power augmentation measures. "Supplemental Capacity" is the capacity over and above the Standard Capacity which is produced with the use of power augmentation measures. LSP estimates the Contract Quantity for each unit to be approximately 270 MW, with the Supplemental Capacity comprising approximately 6 to 12% of this amount. LSP will perform a test each year to demonstrate the capability of each unit.

DELIVERY START DATE AND TERM

The delivery start date will be June 1, 2001 and the term will be ten years from this date.

DELIVERY POINT

MPS's high voltage transmission system.

FUEL ARRANGEMENTS

MPS will be responsible for arranging, procuring, and delivering to the project all fuel required by LSP to deliver energy from each unit to MPS, including, but not limited to, arrangements for fuel supply, fuel transport, nominations and balancing. LSP will be responsible for installing the necessary pipeline facilities to provide the project with access to fuel deliveries.

SCHEDULING AND DISPATCH

The project will be fully dispatchable within the design limits and within MPS's gas supply/transport arrangements. The design limits will include but not be limited to the following:

(i) minimum load equal to 70% of the Contract Quantity;

(ii) the capability to ramp from minimum load up to the Standard Capacity at an average rate no less than 5 MW per minute;

(iii) one start per day for each unit;

(iv) maximum time from MPS's notice of start up to minimum load in accordance with manufacturers' recommendations.

CAPACITY PAYMENT

MPS will pay LSP a capacity payment each month of the contract term commencing on the delivery start date, calculated as follows:

$$CP = CR_N \times CQ \times AAF, \text{ where}$$

CP = the Capacity Payment expressed in dollars for the month,

CR_N = is the Capacity Rate expressed in dollars per kilowatt per month applicable for each contract year "N", equal to $5.50 per kW per month for the first year of project operation, with escalation for subsequent years of project operation at the rate of 2% per year,

CQ = the Contract Quantity of the unit(s), expressed in kW,

AAF = the Availability Adjustment Factor for the month as defined below.

The "Availability Adjustment Factor" will be computed on a twelve month rolling average basis as follows:

$AAF = 1$ for the first twelve months of project operation, and thereafter

$$AAF = AH_{12}/(0.97 \times PH_{12}), \text{ where}$$

AH_{12} = the number of hours during the previous twelve month period that the project was available to deliver the Contract Quantity or delivered energy pursuant to MPS's dispatch orders from an alternate source, prorated for partial outages or derates, and

PH_{12} = the total number of hours during the previous twelve month period less outages caused by force majeure events and scheduled outages approved by MPS, prorated for partial outages or derates.

ENERGY PAYMENT

MPS will pay LSP an amount equal to $1.00 per MWH as of January 1, 1998 escalating annually thereafter at the rate of change in the Gross Domestic Product Implicit Price Deflator for each MWH of energy delivered by LSP to MPS.

MPS will pay for all fuel required to deliver energy scheduled by MPS. A tracking account will be maintained to track the actual amount of fuel required to produce the energy scheduled by MPS and delivered by LSP and the actual delivered price of fuel for such day. If the actual amount of fuel required to produce such energy varies from the amount of fuel required to produce such energy based on the Guaranteed Heat Rate as adjusted for part loading and/or power augmentation, then a balance will accrue in the tracking account for such day. If the actual amount of fuel required to produce such energy on such day is greater than the required amount based on the Guaranteed Heat Rate adjusted for part loading and/or power augmentation, then a positive amount equal to the differential fuel required, expressed in MMBtu, times the delivered cost of fuel, expressed in dollars per MMBtu, for such day will accrue to the tracking account for such day. If the actual amount of fuel required to produce such energy on such day is less than the amount required based on the Guaranteed Heat Rate adjusted for part loading and/or power augmentation, then a negative amount equal to the differential fuel, expressed in MMBtu, times the delivered cost of fuel, expressed in dollars per MMBtu, for such day will accrue to the tracking account for such day. At the end of each month, the tracking account will be cleared and if the tracking account balance is positive, LSP will pay MPS such amount, whereas if the tracking account balance is negative, MPS will pay LSP such amount.

START UP PAYMENT

In the event the number of starts for a unit exceeds 150 per contract year, MPS will pay to LSP a start up payment equal to the start up rate times the number of starts over 150. The start up rate will be $5,000 per start up as of January 1, 1998 escalating annually thereafter at the rate of change in the Gross Domestic Product Implicit Price Deflator.

MPS will also pay for fuel required during start up to reach minimum load. Energy produced during start up will be delivered to MPS at the delivery point.

GUARANTEED HEAT RATE

The "Guaranteed Heat Rate" will be 7.500 MMBtu/MWH (HHV) for the full load Standard Capacity from each unit. If a unit is loaded less than the full load Standard Capacity, the Guaranteed Heat Rate will be adjusted in accordance with manufacturer's adjustment factors to reflect part loading. The Guaranteed Heat Rate for Supplemental Capacity from each unit will be 10.500 MMBtu /MWH (HHV).

BUYOUT OPTION

MPS will have the option to purchase the unit(s) at the end of the contract term by providing notice to LSP, no later than twenty four months prior to the end of the term, of its intention to exercise its purchase option. The buyout price to purchase the unit(s) will be determined as the greater of fair market value or the amount necessary to repay all senior and junior debt and provide the same net present value return to the equity investors as contemplated at the time of financial closing.

COMPLETION GUARANTEES AND SECURITY

In the event that commercial operation has not been achieved by the delivery start date, and to the extent MPS would have otherwise requested deliveries from LSP, LSP at its option will either (i) provide replacement power to MPS, (ii) pay MPS for its reasonable costs associated with securing replacement power, or (iii) pay delay damages payments. LSP will provide certain forms of security to MPS to guarantee that the project will be completed on time and will operate as promised. These include a milestone completion schedule and completion security. Specific details of these securities need to be further discussed with MPS.

SCHEDULED MAINTENANCE

Scheduled maintenance will be performed in accordance with manufacturer's recommendations and prudent practices. The number of days of scheduled maintenance outages per year will be a function of the type of maintenance that is required, which, in turn, will be a function of the number of starts and the number of operating hours for each unit. The total duration of maintenance outages will be no more than 20 days per year except when a major maintenance outage is required, in which case the total maintenance outage days will be no more than 35 days per year. For partial outages, the number of maintenance days will be prorated accordingly. LSP will coordinate scheduled maintenance outages with MPS.

LS POWER
QUALIFICATIONS AND EXPERIENCE

LS Power, LLC and its affiliates ("LS Power") is a leader in the development of greenfield generation facilities serving the United States market. Within the past several years LS Power completed construction of three projects comprising approximately 700 megawatts and has commenced construction on another two projects representing 716 megawatts of capacity. Additionally, LS Power has another 800 megawatts committed pursuant to power purchase agreements, with numerous other projects under development. Given the transition in the electric utility industry, this accomplishment serves as a testament to LS Power's commitment to the United States market and its ability to structure highly competitive, flexible and innovative business arrangements with its customers.

One key to achieving this success is the nature of the relationship that LS Power establishes with its customers. LS Power considers its customers as partners in the projects it develops, and in some cases, actually formalizes this partnership. The Borger and Mustang Projects illustrate this business philosophy.

The Borger Project is being developed by the partnership of LS Power and Quixx Corporation, a subsidiary of New Century Energies. This 216 megawatt facility will sell electricity under a long term power purchase agreement to Southwestern Public Service Company (also a subsidiary of New Century Energies) and steam to the Phillips Petroleum Refinery located near Borger, Texas. The project started construction in October, 1997 and full commercial operation is scheduled for early 1999.

The Mustang Project is also being developed by the partnership of LS Power and Quixx. This 500 megawatt combined cycle facility is located in Denver City, Texas. Once operational, fifty percent of the project will be sold to Golden Spread Electric Cooperative and the balance of the output from the LS Power/Quixx share of the project will be sold under a long term power purchase agreement with Golden Spread. The project commenced construction in December, 1997 and will be completed in two phases, simple cycle in spring of 1999 and combined cycle in late 1999.

LS Power structures business arrangements that provide attractive economics, equitable risk sharing and other features that may include our customer's participation in the selection of project design and site, joint development of the fuel supply strategy, review of operation and maintenance procedures, flexibility in commercial operation/construction schedules and ownership participation options. An example of this is LS Power's Batesville Project which will provide 800 MW of capacity and energy via tolling arrangements with two power purchasers. This project is located in Batesville, Mississippi on the border of the Tennessee Valley Authority and Entergy Systems.

LS Power has been recognized by the industry as a leader in power project development. The 250 megawatt Whitewater, Wisconsin and Cottage Grove, Minnesota

Projects developed by LS Power were embraced not only by our utility customers, but also by the financial markets, state regulators, environmental agencies and local communities. For example, these projects received *Project Finance Monthly's* (a publication of Information Forecast, Inc.) Most Significant Domestic Project Award for 1995. The $332 million of public debt for our Cottage Grove and Whitewater Projects received a rating of Baa2 by Moody's and BBB by Standard and Poor's. This is a rating higher than for any other independent power project financing.

Another key to LS Power's success is its in-house expertise in the areas of cycle design, permitting and regulatory affairs, gas supply and transportation, financing, public relations, and in particular, understanding of the electric utility industry. One cornerstone of our resource base is that several of LS Power's key personnel have spent decades working in the electric utility industry in the areas of planning, transmission/substation design, power plant design, power plant operations and utility management. This experience empowers us to relate well with our customers, appreciate their needs and offer solutions that are responsive to those needs.

LS Power is also strong financially, serving as the general partner of Granite Power Partners II, L.P., a limited partnership which provides development stage funding for the projects developed by LS Power. Financial investors, including the Chase Manhattan Capital Corporation, are limited partners of Granite. Chase is one of the largest financial institutions in the world and has financed billions of dollars worth of independent power projects. LS Power is a privately held company and as such does not disclose financial information. An annual report for Chase is available upon request.

COTTAGE GROVE COGENERATION PROJECT

The Cottage Grove Project is located in Cottage Grove, Minnesota. The project is a fully dispatchable, intermediate load, combined-cycle natural gas-fired (with fuel oil backup) combustion turbine cogeneration facility designed to generate approximately 245 MW of electrical power and approximately 200,000 pounds per hour of steam. Electrical energy is being sold to Northern States Power Company (NSP) under a 30 year agreement which was negotiated pursuant to a competitive selection process administered by NSP and approved by the Minnesota Public Utilities Commission. The facility also produces steam for sale to the 3M Cottage Grove Plant, replacing steam previously produced by coal-fired boilers. The project achieved commercial operation in October, 1997.

The Cottage Grove project was selected in June, 1993 by NSP to provide intermediate capacity and associated energy. The selection was made over strong competition from a variety of different sources (Independent Power Producers, Utilities, and the NSP-sponsored Wheaton Project). The Cottage Grove Project was evaluated to have the lowest cost to NSP and its ratepayers along with many socio-economic benefits to the region.

The Cottage Grove Project has contracted with two domestic suppliers (Natural Gas Clearinghouse and Aquila Energy Marketing Company) under an indexed pricing arrangement. These contracts have been structured with several levels of supply to match nomination commitments on a monthly, daily and no-notice basis. Gas transportation has been arranged under a series of long term contracts with Northern Natural Pipeline Company and Peoples Natural Gas Company (the LDC) that involve capacity release, and a combination of storage, firm and interruptible transportation that assures reliable, cost effective delivery.

Westinghouse Electric Corporation provided turnkey engineering, procurement and construction services for the project. Westinghouse Operating Services Company is currently providing operation and maintenance services.

The permits and approvals for the project included a Certificate of Need, Certificate of Site Compatibility, Air Permit and NPDES Permit. The entire permitting process was quite expeditious compared with previous power generation projects in the state, requiring a total of nine months.

This project was developed by LS Power and was financed jointly with the Whitewater Cogeneration Project via LS Power Funding Corporation. The Senior Secured 144A Bonds were arranged by Chase Securities, Inc. and Morgan Stanley & Company, Inc. S&P's rating of BBB is higher than for any other independent power project. Granite Power Partners, L.P. recently sold its majority ownership interest in this project.

WHITEWATER COGENERATION PROJECT

The Whitewater Cogeneration Facility is located in Whitewater, Wisconsin. The project is a fully dispatchable, intermediate load, combined-cycle natural gas-fired (with fuel oil backup) combustion turbine cogeneration facility designed to generate approximately 245 MW of electrical capacity and approximately 200,000 pounds per hour of steam. Electrical energy is being sold to the Wisconsin Electric Power Company (WEPCO) under a 25 year agreement which was negotiated pursuant to a competitive bidding process administered by the Public Service Commission of Wisconsin. The facility provides steam to several steam customers including the University of Wisconsin at Whitewater. The project achieved commercial operation in September, 1997.

The project was proposed in June, 1993 to WEPCO as an alternative to its own self-generation plans (the Kimberly Project). In November, 1993, the PSCW selected the Whitewater Project over numerous other bidders including the Kimberly Project. The evaluation results concluded the LS Power Project offered the lowest cost to WEPCO and its ratepayers.

The Whitewater Project has contracted with two domestic suppliers under an indexed pricing arrangement. Gas transportation has been arranged under a series of long term contracts with Northern Natural Pipeline Company, Wisconsin Natural Gas Company (the LDC) and another Wisconsin utility. These transportation agreements involve a reverse capacity release, and a combination of storage, firm and interruptible transportation that assures reliable, cost effective delivery.

The permits and approvals for the project included a Certificate of Public Convenience and Necessity, Air Permit and WPDES Permit. The entire permitting process was quite expeditious compared with previous power generation projects in the state, requiring a total of thirteen months.

Ownership, financing, turnkey construction, and O&M arrangements for the Whitewater Project are similar to those for the Cottage Grove Project.

LOCKPORT ENERGY ASSOCIATES, L.P.

LS Power, under contract with the CU Energy Partnership, developed and managed the financing and construction of this 200 MW, $220 million combined cycle gas/oil-fired cogeneration project in Lockport, New York. This project sells power to New York State Electric & Gas Company under a power purchase agreement. The project also supplies up to 300,000 pounds per hour of steam and up to 24 MW of electricity to the Harrison Radiator Division of General Motors under a 15-year contract. The project entered commercial operation in December, 1992.

The Lockport Project has secured gas supply from the combination of two domestic and one Canadian suppliers. These gas supply contracts were the first in the industry that utilized fixed, predetermined pricing for the duration of a 15 year contract term. Natural gas is transported to the project site via the Tennessee Gas Pipeline Company ("TGPL") under a set of 15 year firm transportation agreements. The Canadian supplies are delivered via the NOVA Pipeline, TransCanada Pipeline and TGPL.

The project was engineered and constructed by Chas. T. Main, Engineers & Constructors, a subsidiary of the Parsons Corporation, under a fixed price date certain engineering, procurement and construction contract. The project is operated and maintained by North American Energy Services Company.

Chase Manhattan Bank was the construction and term lender for the project. LS Power negotiated all project contracts and agreements, obtained all federal, state and local permits and approvals, participated in and coordinated the debt placement process of the project. The Lockport Project was the first large cogeneration project developed by LS Power as an independent entity.

BORGER PROJECT

In February of 1997, a joint proposal offered by the partnership of LS Power and Quixx Corporation, then a subsidiary of Southwestern Public Service Company (SPS), was selected via a competitive solicitation process to serve SPS's future power supply needs. The project is located at the Phillips Petroleum Refinery near Borger, Texas and will provide approximately 216 MW of electrical capacity to SPS and process steam to the refinery. The project configuration will utilize two natural gas fueled combustion turbines to produce both the electricity and process steam. The project was financed via a public bond offering arranged by Morgan Stanley Dean Witter and ABN-AMRO Chicago Corporation. Construction commenced in October, 1997 and full commercial operation is scheduled to occur in early 1999. Gas will be supplied to the project by GPM Gas Corporation, a subsidiary of Phillips Petroleum Company.

MUSTANG STATION PROJECT

In August of 1996, Golden Spread Electric Cooperative of Amarillo, Texas selected a joint proposal offered by the partnership of LS Power and Quixx Corporation to serve Golden Spread's power supply needs. The project is being developed by the partnership and once operational, fifty percent of the project will be sold to Golden Spread. The output from the partnership share of the project will be sold under a long term power purchase agreement with Golden Spread. Operational decisions will be handled jointly between the partnership and Golden Spread with the day-to-day operational activities managed by the partnership. LS Power was the lead partner responsible for many of the development activities associated with the project including permitting, procurement of water rights, negotiation of major contracts and arranging project financing. LS Power is currently responsible for managing construction of the project. Project financing was completed in January 1998 and was arranged and underwritten jointly by Societe Generale and CoBank, ACB. Natural gas will be provided to the project by a combination of El Paso Energy Marketing Company and Aquila Energy Marketing Corporation.

The Mustang Project is a 500 megawatt combined cycle facility located in Denver City, Texas being constructed in a phased approach. The project will begin operation in simple cycle phase in late spring 1999 and will be converted to combined cycle operation in late 1999. This project was selected as the result of a highly competitive request for proposal process initiated by Golden Spread in 1994, which included a similar project that would have been entirely developed by Golden Spread. The partnership's proposal, however, provided Golden Spread with the optimum combination of economics, risk mitigation and operational flexibility.

BATESVILLE GENERATION PROJECT

In February, 1996, LS Power entered into an option purchase agreement with Tennessee Valley Authority (TVA) for the supply of 750 megawatts of capacity and associated energy. This agreement was the first of its kind for TVA and was the result of a request for proposals in which 138 bidders responded. In late 1997, due to changed market conditions between the execution of the option agreement and the strike date, TVA elected not to exercise its option.

In December, 1998 LS Power issued a reverse RFP to power marketers and other potential power purchasers in the region. As a result of that process, LS Power recently executed two power purchase agreements for the sale of 800 megawatts of capacity and energy under the terms of a tolling arrangement. Under this arrangement, LS Power guarantees completion, output, availability and efficiency performance, and, in exchange for fuel supplied by the power purchasers, the power purchasers receive net electrical output from the facility.

The project, located in Batesville, Mississippi, has direct access to both the high voltage transmission systems of the Tennessee Valley Authority and Entergy and will interconnect with multiple interstate natural gas pipelines. Construction is scheduled to commence in early summer, 1998, with commercial operation by June, 2000.

FAX COVER SHEET

Basin Electric Power Cooperative
1717 East Interstate Avenue
Bismarck, ND 58501-0564
Phone: (701) 223-0441

- ☐ Fax: (701) 224-5336
- ☐ Fax: (701) 224-5314 (ObjectFax)
- ☐ Fax: (701) 224-5394 (Procurement)
- ☐ Fax: (701) 224-5376 (Basin Travel)
- ☐ Fax: (701) 224-5315 (Comm. & Govern. Relations)
- ☐ Fax: (701) 224-5343 (Office of General Counsel)
- ☐ Fax: (701) 224-5332 (Marketing & Member Services)
- ☐ Fax: (701) 224-5357 (Financial Services)
- ☐ Fax: (701) 255-5143 (Management Information Serv.)

To: Kiah Harris

Company Name: Burns & McDonnell

Fax Number: 816 333 3690

From: Tom Christensen

Department:

☒ For Your Information ☐ For Your Comments Please call Ext. ______

Additional Information:

Original to follow? ☐ Yes ☐ No

By: ☐ Regular Mail ☐ Overnight ☐ Other ______

Number of pages (including cover): 34

Date sent: ______ Time sent: ______

If there are any problems receiving this transmission please call: (701) 223-0441, Ext. 2527; Ext. 2364 (Procurement); Ext. 2416 (Basin Travel); Ext. 2669 (Office of General Counsel); Ext. 2212 (Marketing & Member Services); Ext. 2307 (Comm. & Govern. Relations); Ext. 2652 (Financial Services) or Ext. 3938 (Management Information Services).

BEPC 00114 8/96

**BASIN ELECTRIC
POWER COOPERATIVE**

1717 EAST INTERSTATE AVENUE
BISMARCK, NORTH DAKOTA 58501-0564
PHONE: 701/223-0441
FAX: 701/224-5336

July 2, 1998

CONFIDENTIAL

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

Dear Mr. Harris:

Basin Electric is pleased to respond to your May 22, 1998, request for power supply proposals for Missouri Public Service (MPS). With this proposal, Basin Electric is offering annual MAPP Service Schedule A capacity to MPS. Our proposal covers the June 1, 2000 through May 31, 2004 period, but Basin Electric would consider a shorter or possibly longer duration. Basin Electric's proposal is for up to 100 MW, with the major details of the proposal listed on the attached sheets.

Please contact Tom Christensen with any questions. Due to the number of other potential capacity commitments, Basin Electric reserves the right to withdraw this offer at any time.

Sincerely,

Robert L. McPhail
General Manager

tsc/ms
ATTACHMENT
cc: David Raatz
Tom Christensen

Schedule A Transaction
Annual Participation Power

CONFIDENTIAL

~~Governing Agreement:~~	~~The Mid-Continent Area Power Pool (MAPP) Agreement, as~~ amended, or alternatively a separate two-party agreement could be used.
Transaction Type:	MAPP Service Schedule A: Participation Power Interchange Service, or a mutually agreed to alternate service schedule.
Delivering Party:	Basin Electric Power Cooperative (BEPC)
Receiving Party:	Missouri Public Service (MPS)
Term:	June 1, 2000 through May 31, 2004
Contract Amount:	Up to 100 MW
Contingent on Transmission Availability:	This Agreement would be contingent upon ability to secure Firm Transmission Service.
Power Demand Charge:	Year / Demand Charge: 2000 $12,600/MW-mo; 2001 $13,100/MW-mo; 2002 $13,600/MW-mo; 2003 $14,100/MW-mo; 2004 $14,600/MW-mo Basin Electric would require a provision for adjusting the demand charge upward to cover the cost of any new or increased tax or emission requirements.
Transmission Demand Charge:	Year / Demand Charge: 2000 $2,530/MW-mo; 2001 $2,530/MW-mo; 2002 $2,530/MW-mo; 2003 $2,530/MW-mo; 2004 $2,530/MW-mo The price listed is the estimated firm point-to-point transmission rate which could be used to deliver power from BEPC to MPS under a MAPP long-term tariff. This cost will vary based on the actual transmission costs incurred.
Energy Charge:	Year / Energy Charge: 2000 $12.70/MWh; 2001 $13.10/MWh; 2002 $13.50/MWh; 2003 $13.90/MWh; 2004 $14.30/MWh Basin Electric would require the provision for adjusting the energy charge upward to cover the cost of any new or increased tax or emission requirements.

CONFIDENTIAL

System Contingent Capacity:	The energy supply shall be contingent upon the availability of BEPC's North Dakota coal-fired generation. If a BEPC coal-fired generation resource is taken off-line or substantially curtailed due to equipment failure or required maintenance, BEPC shall have the right but not the duty to interrupt deliveries under an agreement upon notice. BEPC will consider alternate curtailment procedures which would allow BEPC to continue energy deliveries to MPS with the understanding that MAPP emergency procedures will be adhered to, and with consideration of negotiated pricing during those times that BEPC resources are limited.
Availability:	Participation Power provided under this Agreement is intended to be available at all times, subject to unit availability, line loading limitation of the transmission systems involved and all factors generally considered to be covered by Force Majeure. However, under no circumstances will BEPC native firm loads be interrupted to maintain energy deliveries under this agreement.
Scheduling:	Basin Electric would require a minimum schedule commitment equal to 50% of the contract amount and would reserve the right to limit the hourly schedule change based upon the ramping capability of BEPC's North Dakota coal-fired generation.
Capacity Factor:	Basin Electric would require a 70% minimum monthly load factor and a maximum monthly load factor of 90%. If emission credits are supplied to BEPC, the load factor limit could be raised.
Delivery Point:	The energy shall be delivered through the use of the MAPP long-term tariff to MPS's transmission system. Therefore, the delivery point consistent with the use of MAPP long-term tariff transmission is the point(s) of interconnection between MAPP RTC member(s) transmission system(s) and MPS's transmission system.
Energy Losses:	BEPC shall be responsible for all energy losses associated with delivering this power to the MPS's transmission system. MPS shall be responsible for losses on the MPS transmission system.
Contact Person:	Tom Christensen Phone: 701/223-0441, ext. 2242 E-Mail: chrsn@bepc.mapp.org

Aquila Power
10750 East 350 Highway
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AQUILA ENERGY

July 6, 1998

Max A. Sherman
Director
Power Marketing

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

Subject: Request for Proposals for Resource Specific Capacity and Energy for Missouri Public Service

Dear Mr. Harris:

Aquila Power Corporation, a power marketing subsidiary of Aquila Energy, is pleased to respond to Missouri Public Service Company's RFP for resource specific capacity and energy. We are offering capacity from a generating project to be constructed in Mississippi with a commercial operation date of June 1, 2000. We are offering terms of one to four years, with buyout provisions which maximize the flexibility available to MPS. While the project is a combined cycle project, we have structured our proposal as a peaking capacity proposal to meet what we understand to be MPS' capacity requirements.

We believe our prices are competitive and will be economically attractive to MPS. Estimated transmission costs are included in the pricing, as separate components and alternatives priced separately. Actual transmission costs will be the basis for billing.

Because this proposal contains proprietary information relating to our specific generating unit, Aquila Power requests that Burns and McDonnell treat this proposal as confidential in accordance with the confidentiality agreement between Aquila and Burns and McDonnell.

Our proposal shall remain valid for ninety days, unless otherwise extended by Aquila Power. However, pricing will necessarily be subject to revision due to changing market conditions until consummation of a contract between the parties.

We thank you for the opportunity to submit this proposal. Should you have any questions concerning this submittal, please do not hesitate to contact the undersigned. We look forward to meeting Missouri Public Service Company's requirements.

Very truly yours,

Max Sherman

Max Sherman
Director, Power Marketing

Enclosure

cc: David Stevenson
Jeff James

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~~AQUILA POWER CORPORATION PROPOSAL~~

TO

MISSOURI PUBLIC SERVICE

EXECUTIVE SUMMARY

Aquila Power is offering peaking capacity to Missouri Public Service from a generating unit to be built in Batesville, Mississippi, under terms and conditions which are summarized as follows:

- Term: Various terms are offered from June 1, 2000 through May 31, 2004, with buyout options for the last 2 contract years.

- Type of Service: Unit power with a 93% minimum guaranteed annual equivalent availability.

- Designated Unit: A nominal 267 MW combined cycle generating unit to be constructed by LS Power LLC at an industrial park at the Entergy/TVA border in Batesville, Mississippi. The unit is fully permitted. Initial financing and breaking ground to start construction is expected to start in late July 1998. Aquila Power has executed a contract to purchase the capacity and the right to toll energy from the unit for a term well beyond the period requested by the subject RFP.

- Capacity price: We have priced the capacity at the site, and provided a number of transmission options to move the power and associated energy to MPS' system. The least cost firm transmission path from the project to MPS, across Entergy and Ameren, is presently ~$2.00/kW-month. The capacity prices under various options are shown below:

  Option 1
  $10,000/MW-month from June 1, 2000 through September 30, 2000 (100 MW)
  $750/MW-month from October 1, 2000 through May 31, 2001 (75 MW)

  Option 2 (75 MW)
  $3,833.33/MW-month from June 1, 2000 through May 31, 2001

  Option 3 (Up to 100 MW)
  $4,000/MW-month from June 1, 2001 through May 31, 2002
  $4,500/MW-month from June 1, 2002 through May 31, 2003
  $5,000/MW-month from June 1, 2003 through May 31, 2004

  Buyout option cost for termination during the contract year of June 1, 2002 through May 31, 2003 is $10,000/MW. Buyout option cost for termination during the contract year of June 1, 2003 through May 31, 2004 (except on May 31, 2004) is $20,000/MW.

- Energy Price: $100.00/MWh plus the actual cost of transmission losses and/or ancillary services for delivery of the power to MPS. At present, the estimated cost of transmission losses across Entergy and Ameren (the least cost firm path) is $3.41/MWh.

- Delivery Points: APC will deliver energy to MPS' interconnections with the Eastern interconnection. This includes MPS' direct interconnections with Ameren, Associated Electric Cooperative, Inc., Kansas City Power & Light, and Western Resources.

- Transmission: Transmission charges will be billed to MPS at Aqulia's actual cost. Aquila has identified transmission across Entergy and Ameren as the least cost firm transmission path from the Batesville project which meets the RFP requirements. Present prices for firm transmission on this path range from ~$2000/MW-month ~$2162/MW-month, depending on whether annual or monthly firm service is purchased from Entergy. However, Aquila believes that it may be possible for MPS to relax the requirement for firm service to MPS <u>if</u> the capacity were to be delivered across Entergy to the Southwest Power Pool. Aquila has therefore shown transmission pricing in Tab 7 for a variety of alternative scenarios for consideration by MPS.

- Market Conditions: Pricing is necessarily subject to revision due to changing market conditions, up to execution of a contract between the parties.

DESIGNATED GENERATING UNIT

The designated generating unit is a nominal 267 MW combined cycle generating unit to be constructed by LS Power LLC at an industrial park at the Entergy/TVA border in Batesville, Mississippi. The unit is one of three units to be constructed on the site, with a nominal total capacity rating of 800 MW. Aquila Power has executed a contract to purchase the capacity and the right to toll energy from one unit for a term well beyond the period requested by MPS' Request for Proposals. The project will interconnect with both the Tennessee Valley Authority and the Entergy transmission systems at 161 kV. Aquila has been advised that the EPC contractor and generating equipment vendor have been selected. Because these vendor selections have not been made public, Aquila is not able to disclose who these entities are at this time.

LS Power LLC has advised Aquila Power that the project is fully permitted, and provided a copy of the major permits (which are listed below). The project schedule calls for initial financing and breaking ground to start construction in late July 1998, in order to meet a June 1, 2000 in-service date specified in Aquila's power purchase agreement with LS Power.

Major Permits and Approvals for Batesville Project

- Public Service Commission of Mississippi Certificate of Public Convenience and Necessity, Docket No. 97-UA-513, dated December 12, 1997
- State of Mississippi Air Pollution Control Permit No. 2100-00054, dated November 25, 1997 (both permission to construct and permission to operate)
- National Pollutant Discharge Elimination System (NPDES) Permit No. MS0052931, dated December 12, 1997
- Mississippi Permit to Divert or Withdraw for Beneficial Use the Public Waters, Permit No. MS-SW-02744, dated November 25, 1997.
- Federal Energy Regulatory Commission Certification of Exempt Wholesale Generator Status, Docket No. EG98-59-000, dated April 28, 1998.
- U.S. Army Corps of Engineers Nationwide/General Permit Nos. NW07, NW12, NW25, NW26 and GP22, issued December 4, 1997.
- City of Batesville, MS Confirmation of Appropriate Zoning, dated April 24, 1997.

Copies of these permits can be provided upon request.

TERM

Various terms are offered to be as flexible as possible in meeting MPS' requirements:

<u>Option 1</u>
June 1, 2000 through September 30, 2000 (100 MW)
October 1, 2000 through May 31, 2001 (75 MW)
(Aquila is willing to discuss each Option 1 period separately)

<u>Option 2 (75 MW)</u>
June 1, 2000 through May 31, 2001

<u>Option 3 (Up to 100 MW)</u>
June 1, 2001 through May 31, 2002
June 1, 2002 through May 31, 2003
June 1, 2003 through May 31, 2004

Buyout options are offered for termination during the last two contract years of Option 3.

QUANTITY

The following quantities of capacity are offered, using the Options described in Tab 4, above:

<u>Option 1</u>: 100 MW for summer 2000 (June 1, 2000 through September 30, 2000)
75 MW for non-summer months (October 1, 2000 through May 31, 2001)

<u>Option 2</u>: 75 MW June 1, 2000 through May 31, 2001

<u>Option 3</u>: Up to 100 MW for the last three (3) contract years (June 1, 2001 through May 31, 2004)

Options 1 and 2 are mutually exclusive. Aquila would be willing to consider selling the summer and non-summer months in Option 1 separately.

Option 3 may be selected by MPS, if it desires, only if it has agreed to purchase capacity under Options 1 or 2.

CAPACITY PRICE

We have priced the capacity at the site, and provided a number of transmission options to move the power and associated energy to MPS' system at MPS' cost. The least cost firm transmission path from the project to MPS, across Entergy and Ameren, is presently ~$2.00/kW-month. The capacity prices under various options are shown below:

Option 1
$10,000/MW-month from June 1, 2000 through September 30, 2000 (100 MW)
$750/MW-month from October 1, 2000 through May 31, 2001 (75 MW)

Option 2 (75 MW)
$3,833.33/MW-month from June 1, 2000 through May 31, 2001

Option 3 (Up to 100 MW)
$4,000/MW-month from June 1, 2001 through May 31, 2002
$4,500/MW-month from June 1, 2002 through May 31, 2003
$5,000/MW-month from June 1, 2003 through May 31, 2004

Buyout option costs
$10,000/MW for termination during the contract year of June 1, 2002 through May 31, 2003.
$20,000/MW for termination during the contract year of June 1, 2003 through May 31, 2004 (except on May 31, 2004).

The buyout option can be exercised with no less than 12 months' prior written notice by MPS to Aquila Power.

TRANSMISSION SERVICE

Transmission charges will be billed to MPS at Aqulia's actual cost. Aquila has identified transmission across Entergy and Ameren as the least cost firm transmission path from the Batesville project which meets the RFP requirements. Present prices for firm transmission on this path range from ~$2000/MW-month ~$2162/MW-month, depending on whether annual or monthly firm service is purchased from Entergy (refer to Table 1, below). However, Aquila believes that it may be possible for MPS to relax the requirement for firm service to MPS <u>if</u> the capacity were to be delivered across Entergy to the Southwest Power Pool (SPP). This is because capacity delivered to the SPP is expected to be counted by the SPP in order to meet a member utility's reserve capacity obligations (per an Aquila discussion with SPP staff). While the SPP will have a requirement effective October 1, 1998 that firm transmission for purchased capacity is required, there is at present no penalty imposed if this requirement is not met. In addition, the issue of grandfathering capacity transactions which existed before the October 1, 1998 effective date, analagous to grandfathering transmission service transactions entered into before the effective date of the SPP regional transmission tariff, to Aquila's knowledge has not been addressed. There may therefore be an opportunity to grandfather the associated transmission arrangements. For these reasons, Aquila has shown present firm transmission prices in Table 1, below for alternative scenarios for consideration by MPS.

Table 1
Transmission Scenarios and Present Prices
(For capacity from Aquila's designated generating unit in Batesville, MS)

Path	Utility #1 and cost	Utility #2 and cost	Total ($/MW-mo)
Project-Entergy -Ameren-MPS	Entergy $999.10/MW-mo. (incl. 3% cap. Losses) (+$0.20/MWh anc. Svcs.) (annual firm service)	Ameren $11974.52 per MW-yr ($0.21/MWh losses) (annual firm service)	$1996.98
Project-Entergy -Ameren-MPS	Entergy $1163.9/MW-mo. (incl. 3% cap. Losses) (+$0.20/MWh anc. Svcs.) (monthly firm service)	Ameren $997.86 per MW-mo. ($0.21/MWh losses) (monthly firm service)	$2161.76
Project-Entergy -AECI-MPS	Entergy $999.10/MW-mo. (incl. 3% cap. Losses) (+$0.20/MWh anc. Svcs.) (annual firm service)	AECI $21192.87 per MW-yr (+$1.20/MWh losses & anc. svcs.) (annual firm service)	$2765.17

Project-Entergy -AECI-MPS	Entergy $1163.9/MW-mo. (incl. 3% cap. Losses) (+$0.20/MWh anc. Svcs.) (monthly firm service)	AECI $1766.08 per MW-mo. (+$1.20/MWh losses & anc. svcs.) (monthly firm service)	$2929.98
Project-TVA -Ameren-MPS	TVA $2041/MW-mo. (+. 3% losses) (monthly firm service)	Ameren $997.86 per MW-mo. ($0.21/MWh losses) (monthly firm service)	$3038.86

ENERGY PRICE

The offered energy price is $100.00/MWh plus the actual cost of transmission losses and/or ancillary services for delivery of the power to MPS. At present, the estimated cost of transmission losses across Entergy and Ameren (the least cost firm path) is $3.41/MWh.

OPERATION AND MAINTENANCE

Operation

LS Power will be responsible for operation of the designated generating unit. Aquila Power will be responsible for the fuel supply. The unit will be operated and maintained in accordance with equipment manufacturer recommendations.

Maintenance

LS Power will be responsible for maintaining the unit in accordance with equipment manufacturer recommendations. Aquila's contract with LS Power contains strong incentives for LS Power to schedule maintenance during the low load months in the Spring and Fall, and to minimize the annual scheduled maintenance hours subject to manufacturer's recommendations. Scheduled maintenance is not allowed during the period from June 15 to September 15.

The maintenance schedule for the designated unit is determined annually. The criteria and contract conditions for determining the maintenance schedule are attached. Aquila requests this information be treated as confidential.

``Section 5.4 Scheduled Maintenance.

(a) At least thirty (30) Days prior to the Commercial Operation Date and thereafter prior to June 1 of each subsequent calendar year, Purchaser shall provide to Seller a non-binding proposed schedule of its projected Dispatch for, in the case of the first such schedule, the nineteen (19)-Month period beginning on the Commercial Operation Date, and thereafter for the twelve (12)-Month period beginning on January 1st of the following calendar year.

Based on Purchaser's projected Dispatch schedule and subject to Section 5.4(b), Seller shall provide Purchaser with its proposed maintenance schedule for such twelve (12)-Month period within ten (10) Days following receipt of Purchaser's projected Dispatch schedule. Purchaser and Seller shall agree on the expected timing of the Scheduled Maintenance Outages for such twelve (12)-Month period with no Scheduled Maintenance Outages to occur during the period from June 15 to September 15. Scheduled Maintenance Outages may be taken in any number of non-contiguous periods, provided number of Scheduled Maintenance Hours does not exceed the amounts specified in Section 5.4(b). Seller shall coordinate all Scheduled Maintenance Outages with Purchaser by giving Purchaser written notice at least ten (10) Days prior to a Scheduled Maintenance Outage such notice to include the scheduled start date, time, and duration of such Scheduled Maintenance Outage. Unless otherwise agreed by the Parties, acting reasonably, the start date of a Scheduled Maintenance Outage shall occur within one (1) Day of the date the Parties agreed to schedule such Scheduled Maintenance Outage as set forth above. To the extent the start of a Scheduled Maintenance Outage deviates by more than one (1) Day from the schedule that had been agreed to, such deviation shall count towards the 120 hours available to Seller pursuant to Section 5.4(c).

(b) Scheduled Maintenance Outages shall be determined in accordance with manufacturer's recommendations in accordance with formulae provided by relevant equipment manufacturers. The number of Scheduled Maintenance Hours shall be further limited to 336 hours each calendar year in which a minor inspection (e.g. combustion inspection) occurs, 480 hours each calendar year in which a hot gas path inspection occurs, and 840 hours each calendar year in which a Major Inspection occurs. Subject to Purchaser not exceeding 200 Start-Ups per year, the Scheduled Maintenance Outage frequency shall be no greater than annually for a minor inspection, every three (3) years for a hot gas path inspection, and every five (5) years for a Major Inspection; provided, however, that such maintenance frequencies shall be further subject to changes in the manufacturer's recommendations. To the extent Purchaser exceeds 200 Start-Ups in a calendar year, and to the extent manufacturer's recommendations require a greater frequency of maintenance than that described herein, the frequency of such maintenance shall be adjusted in accordance with such manufacturer's recommendations.

(c) If required in accordance with Prudent Industry Practices or manufacturers' recommendations, Seller may utilize up to 120 Scheduled Maintenance Hours per calendar year to perform maintenance repairs at a different time than designated pursuant to Section 5.4(a). Seller shall provide Purchaser with no less than two (2) Business Days prior notice of such requirement; provided that Seller shall not be entitled to make such re-allocation of Scheduled Maintenance Hours during the period from June 15 through September 15 without the prior consent of Purchaser. Seller shall use its best efforts to schedule such Scheduled Maintenance Outages in a manner that allows Scheduled Maintenance Outages of less than eight (8) contiguous hours to occur during Off-Peak Hours.''

AVAILABILITY

The minimum guaranteed annual equivalent availability, once the unit achieves commercial operation, is 93%.

SCHEDULING

Scheduling of power and energy from the designated generating unit will be by MPS to Aquila by 8:30 a.m the previous business day. This deadline is needed to enable Aquila to nominate natural gas for the unit. Schedules shall be submitted by MPS to Aquila Power by facsimile or telephoned instruction to Aquila's designated representative for this transaction. The minimum schedule block is 25 MW for any hour the power is scheduled. The minimum schedule duration is eight (8) consecutive hours. MPS shall also reimburse Aquila for a pro-rata share of start-up costs; for a 267 MW generating unit approximately 3000 MCf of natural gas is required for start-up.

When Aquila is serving MPS from the generating unit, procedures will need to be established to cover the generating unit ramp rates from synchronization to minimum load, and between minimum and full load. This may mean that changes in scheduled hourly deliveries requested by MPS may need to be accommodated over more time than the ten minute ramp across the top of the hour which is normal practice in SPP. In such event, MPS and Aquila will develop procedures, working with transmission providers, to allow longer ramp times if required to facilitate desired schedule changes.

DELIVERY POINTS

- APC will deliver energy to MPS' interconnections with the Eastern interconnection. This includes MPS' direct interconnections with Ameren, Associated Electric Cooperative, Inc., Kansas City Power & Light, and Western Resources.

BUYOUT OPTIONS

Buyout option costs are as follows:

$10,000/MW for termination during the contract year of June 1, 2002 through May 31, 2003.

$20,000/MW for termination during the contract year of June 1, 2003 through May 31, 2004 (except on May 31, 2004).

The buyout option can be exercised with no less than 12 months' prior written notice by MPS to Aquila Power.

CONDITIONS PRECEDENT

Any agreement entered into hereunder will have the conditions precedent to effectiveness of the agreement that:

1. The Project will have financial closing occur by August 15, 1998, unless such condition is waived or extended by Aquila Power.

2. The effectiveness of the agreement shall also be subject to receipt of all required regulatory approvals, including for Aquila, the Federal Energy Regulatory Commission, and including for MPS the Missouri Public Service Commission.

3. Completion of construction and commissioning of the unit as scheduled.

4. Acquisition of firm transmission service as directed by Missouri Public Service.