(4) In its September 1998 briefing, Empire will provide Staff, OPC and intervenors with a summary report that evaluates the overall cost effectiveness of maintaining versus refurbishing versus retiring the generating units at the Riverton Plant, taking into account the uncertainties associated with the following areas - component failure, cost of replacement power, availability of replacement power, peak load growth, environmental regulations, and retail competition. Empire will also provide the Staff an update of the NOX performance on Asbury Plant as it compares to the then current and foreseeable regulations.

(5) In its September 1999 briefing, Empire will provide Staff, OPC and intervenors with a copy of a request for proposal (RFP) if Empire decides to use a competitive bidding process to solicit Empire's capacity needs which begin in the year 2001. In a subsequent briefing, Empire will provide Staff, OPC and intervenors with Empire's evaluation of the proposals that Empire received in response to its competitive RFP, or a briefing on its alternative process of selection. This evaluation should include the elements on risk analysis and plan selection as described in 4 CSR 240-22.070.

Demand-Side Analysis Requirements:

Low-income customers face many market barriers when confronted with new energy efficiency measures, the most obvious being high up-front costs. It is not clear that the existing electric marketplace or the perceived future competitive market will meet these customers' need for energy services. Empire proposes taking an initial step towards meeting this need by refocusing its demand-side efforts on this customer segment. Initially, Empire proposes working in conjunction with assistance agencies to identify low income customers who would benefit from the installation of a Residential Conservation packet.

With respect to 4 CSR 240-22.050 and in lieu of its 1998 filing to meet the requirements in 4 CSR 240-22.050, Empire agrees to provide the following:

**(6) By March 1998, Empire will provide to Staff, OPC and intervenors a report on the partnership(s) developed with assistance agencies and a summary of the number of conservation packets installed.**

**(7) By September 1998, Empire will provide a report to Staff, OPC and intervenors on the survey and research work that it performed in an attempt to identify "Low Income" customers, their demographics, and market barriers.**

**(8) By March 1999, Empire will provide a report to Staff, OPC and intervenors on the analysis it performed to screen demand-side programs for the low income segment and identify potential market barriers for participation for the measures which passed the screening test.**

**(9) By March 1999, Empire will present a report explaining how demand-side measures are incorporated into both demand-side and marketing programs. This report will at least include:**

- **demand-side measures included in all current and planned demand-side and marketing programs;**
- **for those measures that did not pass measure screening, but were included in a program, a description of why they were included in a program;**
- **for those measures that did pass the measure screening, but were not**

included in a program, a description of why those measures were not included in a program;

- estimates of the demand and energy impacts of current and planned demand-side programs and marketing programs containing demand-side measures;

- a description of how the determination is made as to which energy services will be offered for competitive purposes and which will be offered for other purposes;

- a description of the DSM programs for low income that were explored or implemented in partnership with assistance agencies.

(10) Empire will update Staff, OPC and intervenors in its twice a year briefings on the status of its demand-side and marketing programs. These updates will include:

- Estimated demand and energy impacts of implemented and planned programs;

- Evaluation results on market barriers and customer market segments;

- Implementation and evaluation schedules;

- A description of how Empire determines whether energy services will be offered for competitive purposes or for other purposes;

- Its list of current and planned energy services that are or will be offered for competitive purposes and those which will be offered for other purposes; and

- *Its progress in providing efficient basic service for low-income customers* and related programs for low-income customers.

Contingency Plan Requirements:

With respect to 4 CSR 240-22.070 and in lieu of its 1998 filing to meet the requirements in 4 CSR 240-22.070, Empire agrees to file:

**(11) By March 1, 1999 - a contingency plan that includes the following elements:**

- **A set of contingency options that are judged to be appropriate responses to extreme outcomes of the critical uncertain factors;**

- **An explanation of why these contingency options are judged to be appropriate responses to the specified outcomes;**

- **A process for monitoring the critical uncertain factors on a continuous basis and reporting significant changes in a timely fashion to those managers or officers who have the authority to direct the implementation of contingency options when the specified limits for uncertain factors are exceeded; and**

- **Consideration of the following critical uncertain factors in Empire's contingency analysis with an explanation of how these limits were determined:**

- **The price of purchases of short-term capacity and energy, as well as**

**how those prices might vary with increasing demands made by Empire within a given year;**

- **The limits to the amount of capacity available for purchase in the short-term markets;**

- **The level of growth in summer peak demand and the likelihood of achieving demand-side reductions;**

- **The operational life of Empire's existing generating units; and**

- **Natural gas price and availability.**

Filing Requirements:

The parties to this agreement understand that if there are any significant changes in the preferred resource plan which Empire currently has on file with the Commission, the requirements of 4 CSR 240-22.080(10) still apply. Specifically, Empire will notify the Commission within sixty (60) days of its determination to change its preferred resource plan.

WHEREFORE, the signatories respectfully request the Commission to issue its order approving the terms of this Joint Agreement as soon as practicable.

Respectfully submitted,

Roger Steiner by GWD

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ATTORNEY FOR THE EMPIRE DISTRICT ELECTRIC COMPANY

## CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing have been mailed or hand-delivered to all counsel of record this 5th day of December, 1997.

Gary W. Duffy

Gary W. Duffy

**STATE OF MISSOURI**

**PUBLIC SERVICE COMMISSION**

At a Session of the Public Service

Commission held at its office

in Jefferson City on the 25th day of June, 1998.

In the Matter of the UtiliCorp United )

Inc.=s Electric Resource Plan ) **Case No. EO-98-316**

Pursuant to 4 CSR 240-22. )

**ORDER REGARDING THE UTILICORP UNITED INC. =S**

**INTEGRATED RESOURCE PLAN AND JOINT AGREEMENT**

This case was opened on January 28, 1998, for the purpose of receiving and reviewing a request for extension of the time for filing the periodic integrated resource plan filings of Utilicorp United Inc. d/b/a Missouri Public Service (MPS) pursuant to 4 CSR 240-22 of the Commission=s rules. On February 3 a notice was issued granting an extension of time to April 6, 1998 to file the periodic integrated resource plan filing. On April 7 the Commission granted another request for an extension of time until April 13. On April 13 MPS, the Staff of the Commission (Staff) and the Office of Public Counsel (OPC) filed a proposed joint agreement regarding MPS=s Electric Resource Plan (ERP). MPS filed its most recent resource plan filings in March and April 1995, Case No. EO-95-187. After review by the Staff and the OPC, a joint agreement was reached and approved by the Commission on March 29, 1996. In the April 13, 1998 proposed joint agreement, the parties detail the reasons why the filings in accordance with 4 CSR 240-22.080(10) are no longer appropriate. Those reasons include changes made to the plans submitted in MPS=s March and April 1995 filings, including the following:

1) Increase in the forecasted peak demand growth from 1.8% to 2.8% and in the forecasted energy growth rate from 2.2% to 3.0%;

2) An additional summer purchase power contract between MPS and Kansas City Power and Light Company for 30 MW for 1997, 60 MW for 1998 and 90 MW for 1999;

3) Negotiations for leased generation on 267 MW of combustions turbine capacity, including 20 MW for 1999, 124 MW for 2000, 62 MW for 2002 and 61 MW for 2004;

4) Replacement of purchase power contracts, starting with 280 MW for 2000 and an additional 115 MQ for 2001.

Additionally, other factors noted were changes in the capacity margin requirements by the MoKan Power Pool and ongoing changes in the electric industry itself.

The parties view the next several years to be a transitional period in the electric industry in the state of Missouri. The parties state that the electric industry will focus on issues surrounding potential retail competition. The parties are proposing a series of briefings and periodic reports, partially to improve the understanding of the parties regarding the impact of anticipated retail competition on the electric resource planning process. The briefings and periodic reports are detailed in the proposed agreement.

The parties have also stated that the proposed agreement constitutes a reasonable alternative to the requirements in the joint agreement on MPS=s resource plan filing approved by the Commission on March 29, 1996 and full compliance with the filing requirement as set out in 4 CSR 240-22.

After review the Commission finds the joint agreement to be reasonable in that it is designed to shift emphasis from the filing requirements of Chapter 22 of 4 CSR 240 and to go forward with issues that jointly relate to electric resource planning and retail competition in an efficient and effective manner. The Commission will approve the agreement as an alternative plan for MPS=s compliance with the Commission=s integrated resource planning rules, and will order MPS to comply with the terms and conditions of the agreement.



**IT IS THEREFORE ORDERED:**

1. That the joint agreement between the parties, appended to this

order as Attachment A and incorporated herein, is found to be reasonable and in the public interest and is hereby approved in accordance with 4 CSR 240-22.

2. That Utilicorp United Inc. d/b/a Missouri Public Service is hereby ordered to comply with the terms and conditions of the joint agreement.

3. That this order shall become effective on July 7, 1998.

**BY THE COMMISSION**

**Dale Hardy Roberts**

**Secretary/Chief Regulatory Law Judge**

(S E A L)

Lumpe, Ch., Crumpton, Schemenauer

and Drainer, CC., concur.

Murray, C., absent.

Register, Regulatory Law Judge

# Missouri Public Service Commission

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April 13, 1998

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

**RE: Case No. EO-98-316 - UtiliCorp United Inc.'s Electric Resource Plan**

Dear Mr. Roberts:

Enclosed for filing in the above-captioned case are an original and fourteen (14) conformed copies of a **JOINT AGREEMENT.**

This filing has been mailed or hand-delivered this date to all counsel of record.

Thank you for your attention to this matter.

Sincerely yours,

Roger W. Steiner
Assistant General Counsel
(573) 751-7434
(573) 751-9285 (Fax)

RWS/wf
Enclosure
cc: Counsel of Record

## BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

| | | |
|---|---|---|
| In the Matter of The UtiliCorp United Inc.'s Electric Resource Plan Pursuant to 4 CSR 240-22. | ) ) ) | Case No. EO-98-316 |

### JOINT AGREEMENT

Comes now UtiliCorp United Inc. d/b/a Missouri Public Service ("MPS" or "Company"); Staff of the Missouri Public Service Commission ("Staff"); and the Office of Public Counsel ("OPC"), pursuant to 4 CSR 240-22.080(8) of the Commission's rules on Electric Utility Resource Planning, and submit this Joint Agreement regarding MPS's Electric Resource Plan ("ERP") in Case No. EO-95-187 and the scheduled filing of a new ERP by MPS in 1998 specified in Case No. EO-98-316.

This document constitutes a Joint Agreement among MPS, the Staff and OPC. Furthermore, the parties waive their respective rights under section (9) of 4 CSR 240-22.080 to file a response or comments. Therefore, the parties submit that they are not asking for, nor from their perspective is there a need for, a hearing by the Commission. The parties are ready and willing to respond to any questions of the Commission which may arise during its consideration of this Joint Agreement.

This Joint Agreement has resulted from extensive negotiations among the signatories and the terms hereof are interdependent. In the event the Commission does not approve and adopt this Joint Agreement in total, then this Joint Agreement shall be void and no signatory shall be bound by any of the agreements or provisions hereof.

In the event the Commission accepts the specific terms of the Joint Agreement, the parties waive, with respect to the issues resolved herein: their respective rights pursuant to

Section 536.080.1, RSMo 1994 to present testimony, cross-examine witnesses, and present oral argument and written briefs; their respective rights to the reading of the transcript by the Commission pursuant to Section 536.080.2 RSMo 1994; and their respective rights to judicial review pursuant to Section 386.510 RSMo 1994.

*If requested by the Commission, the Staff shall have the right to submit to the Commission a memorandum explaining its rationale for entering into this Joint Agreement.* Each party of record shall be served with a copy of any memorandum and shall be entitled to submit to the Commission, within five (5) days of receipt of Staff's memorandum, a responsive memorandum which shall also be served on all parties. All memoranda submitted by the parties shall be considered privileged in the same manner as are settlement discussions under the Commission's rules, shall be maintained on a confidential basis by all parties, and shall not become a part of the record of this proceeding or bind or prejudice the party submitting such memorandum in any further proceeding or in this proceeding whether or not the Commission approves this Joint Agreement. The contents of any memorandum provided by any party are its own and are not acquiesced in or otherwise adopted by the signatories to the Joint Agreement.

The Staff shall also have the right to provide, at any agenda meeting at which this Joint Agreement is noticed to be considered by the Commission, whatever oral explanation the Commission requests, provided that the Staff shall, to the extent reasonably practicable, provide the other parties with advance notice of when the Staff shall respond to the Commission's request for such explanation once such explanation is requested from Staff. Staff's oral explanation shall be subject to public disclosure, except to the extent it refers to matters that are privileged or protected from disclosure pursuant to any Protective Order issued in this case.

## I. THE CONTEXT OF THE AGREEMENT

### A. The Status of MPS's Resource Plans

In March and April of 1995, in Case No. EO-95-187, MPS filed with the Commission its Electric Resource Plan. The ERP filing was reviewed by the Staff and the OPC as well as intervenors and the findings were reported to the Commission. The reports and the subsequent agreements between the parties associated with these reviews were also filed in Case No. EO-95-187. The parties filed a joint agreement October 2, 1995. The Commission issued an order in Case No. EO-95-187 on March 29, 1996 which incorporated the joint agreement.

On January 28, 1998, MPS filed for an extension of time to allow the Company, Staff and the OPC to work out a joint agreement respecting MPS's next scheduled ERP filing. On February 3, 1998, the Commission granted MPS its request for an extension of time. This Joint Agreement represents the issues and procedures that the parties have negotiated to replace MPS's February 3, 1998 ERP filing, which was subsequently extended to April 6, 1998 and later to April 13, 1998.

In a meeting held January 22, 1998, MPS met with Staff and the OPC to present the current status of its resource plans. There had been significant changes made to the plans submitted in MPS's April, 1995 filing for Missouri Public Service territory. These changes include the following:

1) Increases in the forecasted peak demand growth rate from 1.8% to 2.8% and in the forecasted energy growth rate from 2.2% to 3.0%;

2) An additional summer purchase power contract between MPS and Kansas City Power & Light Company for 30 MW for 1997, 60 MW for 1998 and 90 MW for 1999;

3) Negotiations for leased generation on 267 MW of combustion turbine capacity, including 20 MW for 1999, 124 MW for 2000, 62 MW for 2002 and 61 MW for 2004;

4) Replacement of purchase power contracts, starting with 280 MW for 2000 and an additional 115 MW for 2001.

Additionally, during December, 1996, the MOKAN Power Pool ("MOKAN") executive committee agreed to reduce the capacity margin requirement for its members from 15.3 percent to 13.04 percent, effective for the contract year beginning June 1, 1997. MPS is a member of MOKAN. This reduction was allowed within the guidelines of the Southwest Power Pool ("SPP"). The SPP guidelines basically state that capacity margins can be as low as 15.3 percent in any system without the performance of a loss of load probability ("LOLP") study and that capacity margins can be as low as 13.0 percent if an LOLP study shows loss of load probability of less than one time in a ten year period. The MOKAN and SPP LOLP studies that were performed supported a reduction in capacity margin for the MOKAN system to 13.04 percent. This lower capacity margin requirement from the power pool therefore reduces the amount of capacity which MPS has to have to meet reserve margin requirements.

As a result, MPS's forecasted future capacity requirements are reduced. MPS's current 1999-2006 forecasts show a need for base capacity of 397 MW starting in contract year 2000 and increasing yearly to 881 MW in the contract year 2006. This capacity need comes from: the expiration of three existing capacity contracts; the expiration of leases on several combustion turbine units; and projected load growth. MPS's preferred resource acquisition strategy is to issue a request for proposal ("RFP") to fill part of the capacity requirements, and to negotiate new lease arrangements. In addition, MPS will evaluate the option of going to the short-term capacity markets.

B. Changes in the Electric Industry

The changes in the electric industry since the Commission adopted its Electric Resource Planning Rules have been extensive. In 1993, the electric industry in Missouri was still viewed as having a vertically integrated structure in which the utility reading customers' meters is the same one adding generation plant to meet the growing demands of those same customers. Building new generation plants or long-term purchases from available capacity were generally considered the standard ways to meet growing demands. While competitive bidding for supply-side resources was being considered by some utilities in Missouri, the resulting short-term purchased power agreements were generally seen as a method for filling in reserve requirements on a year-to-year basis and delaying construction of new generation plant. In the context of emerging competition for retail customers, MPS is now focusing on shorter term planning horizons and looking to short-term purchases acquired through competitive bids as the preferred method for meeting resource requirements.

At the time the Commission's Electric Resource Planning rules were adopted, demand-side resources were generally considered as peak shaving or conservation. Peak shaving had the greatest potential for lowering the present value of revenue requirements without raising rates. Retail competition has raised a concern by the utilities about the potential for conservation options raising rates and increasing the likelihood of losing customers to alternative generation suppliers. At the same time, increasing competition to be the customer's energy services provider has resulted in most utilities focusing on planning and implementing marketing programs, some of which have demand-side components.[1]

C. Reports and Briefings During the Transition

In Missouri, the next several years is being viewed by many as a transition period during which the electric industry's focus will be on issues surrounding retail competition. To accommodate what is believed to be a workable transition for those resources involved in the electric resource planning filings and reviews, this Joint Agreement proposes periodic reports and twice-a-year briefings by MPS on its resource implementation plans.

The intent of having scheduled briefings by MPS is to provide a forum in which an ongoing dialogue will occur about the increasing effect that the potential for retail competition is having on MPS's supply-side and demand-side resource acquisition process. The supply-side emphasis of these meetings will be on the emerging market structures for wholesale generation resources. The demand-side will focus on the least-cost provision of electric services for low-income customers. The primary goal of MPS's planning process will remain to provide low cost, safe, and reliable electrical energy to its customers while at the same time positioning the Company for possible retail generation choice.

The parties to this Joint Agreement recognize the Commission's order in Case No. EW-97-245 as having two possible connections to this Joint Agreement. First, a significant

[1]The distinction between demand-side and marketing programs is that demand-side programs focus on removing market barriers that are obstacles to customer implementation of energy efficiency measures, while marketing programs are designed to sell energy services in a market environment that is competitive. Energy services, at their broadest, are defined as products and services that are related to selling and delivering energy. In the State of Missouri, entities other than utilities can offer energy services excluding energy itself. These energy services can result in improved operational efficiencies to the utilities' customers.

level of resources will need to be devoted to the questions raised by the possibility of retail competition. The time and efforts of those scheduled to file and review electric resource plans takes resources away from these critical questions. Second, there are longer-term questions about how the objectives of the Commission's Electric Utility Resource Planning rules might change or be better implemented in the context of retail competition.

The intent of this Joint Agreement is to provide a way for the parties to shift the emphasis from the filing requirements of the Commission's Electric Resource Planning rules as they apply to MPS's second resource plan filing, and going forward on issues that jointly relate to electric resource planning and retail competition. It is the hope of the parties that this will free significant resources that can then be focused on the longer-term questions concerning retail competition. One of the purposes of the scheduled briefings is to improve the understanding of the parties regarding the impact of retail competition on the electric resource planning process.

The briefings and periodic reports detailed in the next section of this Joint Agreement are not intended to be a full and comprehensive substitute for the detailed analysis requirements that are set forth in the Electric Utility Resource Planning rules. Therefore, since this process is different from the requirements of 4 CSR 240-22, the objectives achieved by this process may be different from the objectives that are set forth in 4 CSR 240-22.010. However, the parties agree that this Joint Agreement constitutes a reasonable alternative to (1) the requirements in the joint agreement to MPS's March/April, 1995 electric resource plan filing and to (2) full compliance with the rules for MPS's April, 1998 filing. MPS's next filing pursuant to 4 CSR 240-22 is scheduled for February 6, 2001.

If the Commission rescinds or suspends the operation of 4 CSR 240-22 before the requirements of this Joint Agreement are fulfilled, the parties agree that MPS will not be required to continue the analysis and make the filings herein scheduled. If the Commission modifies 4 CSR 240-22, or for any other reason, the Commission rescinds, suspends the operation of, or modifies 4 CSR 240-22 before the scheduled dates set out herein, the parties agree to renegotiate the terms of this Joint Agreement to meet the stated intent of the Commission, and in the event that a new agreement cannot be reached, the parties may present their positions to the Commission for final determination.

## *II. THE CONTENT OF THE AGREEMENT*

Resource Plan Requirements:

In lieu of MPS's scheduled 1998 filing to meet the requirements of 4 CSR 240-22, the parties agree that MPS will brief the Staff, OPC and intervenors on or about August 1, 1998; February 1, 1999; August 1, 1999; February 1, 2000; and August 1, 2000.

**(1) These briefings shall include information on the following:**

- **Any changes in load forecasts for seasonal class energy and peaks with an explanation for those changes;**
- **Any changes in implementation plans for both demand-side and supply-side resources with an explanation for those changes; and**
- **Any changes in uncertainties, sensitivities, risks and contingency plans with an explanation for those changes.**

Load Analysis and Forecasting Requirements

With respect to 4 CSR 240-22.030 and in lieu of its 1998 filing to meet the requirements in 4 CSR 240-22.030, MPS will meet the following load analysis and forecasting filing requirements.

(2) In its August, 1998, 1999, and 2000 briefings, MPS will provide Staff, OPC and intervenors with the information regarding the status of the following activities:

- Update to its historical data base on driver variables, seasonal energy and peak demands for its major classes;
- Forecasts of units and use per unit by season for the Residential and Commercial classes;
- Forecasts of annual energy by end-use for the Residential and Commercial classes;
- Forecasts of seasonal energy for all other classes;
- Forecasts of driver variables for all classes at the appropriate level of aggregation; and
- Report on the load forecast that documents any changes made in load forecasting methods, compares both load forecasts and driver variable forecasts to historical trends and compares load forecasts and driver variable forecasts to those from the previous year.

Updated forecasts and historical data bases will be provided as developed by MPS for planning purposes but not less than every three (3) years, first beginning August, 1998.

Supply-Side Resource Requirements:

MPS's current 1999-2006 forecast shows a need for additional base capacity of 397 MW starting in contract year 2000 and increasing yearly to 881 MW in the contract year 2006. MPS plans to issue a RFP, utilize short term capacity markets and renegotiate the combustion turbine leases to fill the capacity requirements.

With respect to 4 CSR 240-22.040 and in lieu of its 1998 filing to meet the requirements in 4 CSR 240-22.040, MPS will meet the following supply-side filing requirements:

(3) In its August 1998, briefing, MPS will provide Staff, OPC and intervenors with a summary report of a reoptimized supply side only plan. The report will include a presentation on the derivation of avoided costs that will be used in screening demand-side measures.

(4) In its August 1998 briefing MPS will provide to Staff, OPC and intervenors an update on the renegotiation of the leases for the combustion turbine generating units, including an evaluation of possible options, such as: renew lease on a short term basis, renew lease on a long term basis, purchase the units, negotiate a capacity only contract, joint ownership, or cancel the lease and replace the capacity with new units or capacity contracts. This evaluation should include the possibility of retail competition.

(5) In its February 1999 briefing MPS will provide to Staff, OPC and intervenors a summary report that evaluates the overall cost effectiveness of maintaining versus refurbishing versus retiring of existing generating units, taking into account the uncertainties associated with the following areas - component failure, cost of replacement power, availability of replacement power, peak load growth, environmental regulations, fuel costs, and retail competition.

(6) At the time MPS begins to implement a competitive bidding process to solicit capacity for its forecasted needs, MPS will provide to Staff and OPC copies of the competitive bidding RFPs at least 45 days prior to sending out each RFP. Staff and OPC will review said RFP and provide comments to MPS within 30 days of receiving the RFP.

(7) Thirty (30) days before awarding contracts to successful bidders, MPS will provide to Staff and OPC its evaluation of the proposals received in response to its RFP for its forecasted capacity needs. This evaluation will include the elements of risk analysis and plan selection as described in 4 CSR 240-22.070.

Demand-Side Analysis Requirements:

Low-income customers face many market barriers when confronted with new energy efficiency measures, the most obvious being high up-front costs. It is not clear that the existing electric marketplace or the perceived future competitive market will meet these customers' need for energy services. MPS proposes taking an initial step towards meeting this need by refocusing its demand-side efforts on this customer segment. Initially, MPS proposes working in conjunction with assistance agencies to identify low-income customers who would benefit from the installation of energy conservation measures and assistance.

With respect to 4 CSR 240-22.050 and in lieu of its 1998 filing to meet the requirements in 4 CSR 240-22.050, MPS agrees to the following:

(8) **In its August, 1998 briefing, MPS will provide to Staff, OPC and intervenors a report containing the results of the survey and research work it has performed in an attempt to identify "low-income" customers, their demographics, and market barriers to implementation of energy efficiency. If this report is not completed by this briefing, MPS will provide a status report and a time line for completion. This report will be provided to Staff, OPC and intervenors no later than MPS's February, 1999 briefing.**

(9) By November 1, 1998, MPS will provide a status report to Staff, OPC and intervenors that outlines the progress it has made towards completing the tasks set forth in item (10) below.

(10) By February 1, 1999, MPS will perform screening analysis on demand-side measures and programs for the low-income segment and identify potential market barriers for participation for the measures and programs which pass the screening test. By February 1, 1999, MPS will provide a report to Staff, OPC and intervenors that: (1) describes said screening, analysis and market barrier identification, (2) explains how demand-side measures for the low-income segment are incorporated into demand-side programs and (3) describes how these programs will be implemented. This report will include

- For those measures that did not pass measure screening, but were included in a program, a description of why they were included in a program;
- For those measures that did pass the measure screening, but were not included in a program, a description of why those measures were not included in a program;
- Estimates of the demand and energy impacts of current and planned demand-side programs and marketing programs containing demand-side measures;

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- A description of the demand-side programs for low-income that were explored or implemented in partnership with assistance agencies;

- MPS's progress in providing efficient basic service for low-income customers and related programs for low-income customers; and

- Program descriptions, implementation dates, participation goals (number of customers) and annual budgets for the current and planned demand-side programs and marketing programs containing demand-side measures.

(11) MPS will update Staff, OPC and intervenors in its twice a year briefings on the status of its demand-side and marketing programs. These updates will include:

- Demand-side measures included in all current and planned demand-side and marketing programs;

- Estimated demand and energy impacts of implemented and planned programs;

- Evaluation results on market barriers and customer market segments;

- Implementation and evaluation schedules;

- A description of how MPS determined whether energy services were offered for competitive purposes or for other purposes;

- MPS's list of current and planned energy services that are or will be offered for competitive purposes and those which will be offered for other purposes; and

- An update of the partnership(s) developed with assistance agencies to provide MPS's low income customers with energy conservation measures and assistance.

Contingency Plan Requirements:

With respect to 4 CSR 240-22.070 and in lieu of its 1998 filing to meet the requirements in 4 CSR 240-22.070, MPS agrees to provide the following:

(12) In its August, 1999 briefing, MPS will provide to Staff, OPC and intervenors a contingency plan that includes the following elements:

- A set of contingency options that are judged to be appropriate responses to extreme outcomes of the critical uncertain factors;

- An explanation of why these contingency options are judged to be appropriate responses to the specified outcomes;

- A process for monitoring the critical uncertain factors on a continuous basis and reporting significant changes in a timely fashion to those managers or officers who have the authority to direct the implementation of contingency options when the specified limits for uncertain factors are exceeded; and

- Consideration of the following critical uncertain factors in MPS's contingency analysis with an explanation of how these limits were determined:

  ① The price of purchases of capacity and energy, as well as how those prices might vary with increasing demands made by MPS within a given year;

  ② The amount of capacity available from demand-side resources;

  ③ The level of growth in summer peak demand and the likelihood of achieving demand-side reductions;

  ④ The operational life of MPS's existing generating units; and

  ⑤ Natural gas price and availability.

Filing Requirements:

The parties to this Joint Agreement understand that if there are any significant changes in the preferred resource plan which MPS currently has on file with the Commission, the requirements of 4 CSR 240-22.080(10) still apply. Specifically, MPS will notify the Commission within sixty (60) days of its determination to change its preferred resource plan.

WHEREFORE, the signatories respectfully request the Commission to issue its order approving the terms of this Joint Agreement as soon as practicable.

Respectfully submitted,

Roger W. Steiner
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Missouri Bar No. 21510

Attorney for Missouri Public Service
Brydon, Swearengen & England
P.O. Box 456
Jefferson City, MO 65102
(573) 635-7166
(573) 634-7431 (Fax)

## CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing have been mailed or hand-delivered to all counsel of record as shown on the attached service list this 13th day of April, 1998.

**Service List for Case No. EO-98-316**
**Revised: April 13, 1998**

James W. Swearengen
Brydon, Swearengen & England
P.O. Box 456
Jefferson City, MO 65102

Lewis R. Mills, Jr.
Office of the Public Counsel
P.O. Box 7800
Jefferson City, MO 65102

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

April 7, 1998

UTILICORP UNITED

ENERGYONE

Mr. Mike Proctor
Federal/State Projects
Missouri Public Service Commission
310 West High Street
Jefferson City, MO 65101

RE: Missouri Public Service Request for Proposal

Dear Mr. Proctor:

After our meeting on March 31, MPS was notified that KCPL was withdrawing its proposal to provide firm summer peaking energy to MPS for the years 2000 and 2001.

As a consequence, MPS need for additional power supply resources is 325 MW in 2000 and 500 MW in 2001. This need is based on current load growth forecasts and the expiration of the following purchase power contracts:

| Provider | Megawatts | Expiration Date |
|---|---|---|
| KCPL | 90 | September 30, 1999 |
| AECI | 190 | May 31, 2000 |
| UE | 115 | May 31, 2001. |

The enclosed Request for Proposal (RFP) is hereby submitted to the MPSC staff and the OPC for review and comment.

MPS intends to incorporate any comments received from the MPSC staff and the OPC and issue the RFP on May 29, 1998. Proposals will be due on July 3, 1998.

Please call me at (816) 936-8639 with any comments, suggestions or questions.

Sincerely,

Frank A. DeBacker
Frank A. DeBacker
VP - Fuel & Purchased Power

Attachment

cc: Mr. Ryan Kind, Office of the Public Counsel w/ attachment
Mr. John McKinney, UCU w/ attachment

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

# MPS-1998RFP



Spring, 1998

## A. General

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

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

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

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

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

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

Proposals shall be addressed to the following and must be received no later than 5:00p.m. C.D.S.T., July 3, 1998.

UtiliCorp Energy Group
Attn: Frank A. DeBacker
10700 East 350 Highway
Kansas City, MO 64138
Ph: (816) 936-8639
Fax: (816) 936-8695
E-mail: fdebacke2@utilicorp.com

## B. Contract Capacities and Periods

Proposals are requested for the seasonal and annual capacity amounts shown in Table 1.

Note that the amounts shown are not mutually exclusive. For example, assuming that appropriate proposals are submitted, UCU may elect to purchase one of the following portfolios to meet the needs of MPS from 6/1/2000 - 5/31/2001:

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

**Table 1: MPS Capacity Need**

| Contract Period | | Capacity Amount (MW) | | |
|---|---|---|---|---|
| From | To | Jun-Sep Capacity | Oct-May Capacity | Jun-May Capacity |
| 6/1/2000 | 5/31/2001 | Up to 325 | Up to 75 | Up to 325 |
| 6/1/2001 | 5/31/2002 | Up to 500 | Up to 250 | Up to 500 |

### *C. Point(s) of Delivery*

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

### D. Capacity Pricing

Capacity price at the point(s) of delivery **must** be stated in $/MW-mo, fixed for the contract term.

### E. Energy Pricing

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

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

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

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

## F. Transmission

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

## G. Scheduling

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

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

## H. Availability

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

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

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

## I. UCU Proposal & Joint Projects

UCU may elect to submit an EWG proposal in response to this RFP. If it chooses to submit a proposal, all proposal evaluations will be performed by an independent third party approved by the Missouri Public Service Commission

(MPSC). Any contract between MPS and the EWG would be subject to the approval of the MPSC.

Proposals for joint projects which would provide partial ownership through equity participation by UCU are invited. Such projects would also be evaluated by an independent third party and any contract subject to the approval of the MPSC.

## J. Contact

For additional information regarding this RFP, contact Frank A. DeBacker through the means listed in Section A above.

Commissioners

SHEILA LUMPE
Chair

HAROLD CRUMPTON

CONNIE MURRAY

ROBERT G. SCHEMENAUER

M. DIANNE DRAINER
Vice Chair

# Missouri Public Service Commission

POST OFFICE BOX 360
JEFFERSON CITY, MISSOURI 65102
573-751-3234
573-751-1847 (Fax Number)
http://www.ecodev.state.mo.us/psc/

CECIL I. WRIGHT
Executive Director

WESS A. HENDERSON
Director, Utility Operations

GORDON L. PERSINGER
Director, Advisory & Public Affairs

ROBERT SCHALLENBERG
Director, Utility Services

DONNA M. KOLILIS
Director, Administration

DALE HARDY ROBERTS
Secretary/Chief Regulatory Law Judge

DANA K. JOYCE
General Counsel

May 1, 1998

Mr. Frank DeBacker
VP - Fuel & Purchased Power
UtiliCorp United, Inc.
10750 East 350 Highway
P.O. Box 11739
Kansas City, MO 64138

Dear Mr. DeBacker:

In your letter of April 7, you asked that we call you with any comments, suggestions or questions regarding the Request for Proposal (RFP) which Missouri Public Service (MPS) / UtiliCorp United, Inc. (UtiliCorp) intends to issue on May 29, 1998. The staff of the Missouri Public Service Commission (Staff) appreciates the opportunity to review and comment on the procedures MPS is considering following to obtain additional power supply resources, and we will take this opportunity to comment. Nonetheless, we want to be very clear that this letter should not be viewed as conferring any type of pre-approval to the procedures that MPS/UtiliCorp ultimately follows and the decisions it makes.

The Staff has major concerns regarding Section I of the proposed RFP. First, if UtiliCorp is seriously considering bidding on MPS's power needs as an EWG, then UtiliCorp and MPS will not necessarily have the same interests respecting the pursuit of additional power supply resources. At the outset of going down this path, there is a need to identify: (1) the division (personnel) that will be working on the RFP as an EWG bidder as distinct from representing MPS in the issuance and evaluation of the RFP; and (2) the details of how the proposals will be evaluated and the contracts awarded.

Second, if the division (personnel) of UtiliCorp that sends out the RFP is the same division (personnel) that intends to submit a proposal in response to the RFP, at a minimum this would give the appearance of providing a bidding advantage to that division (personnel). The RFP needs to be clear about who has written the RFP, on behalf of who it is written, and that this UtiliCorp/MPS division (personnel) is not also submitting a bid. If there is an appearance of UtiliCorp providing an advantage to its own bid, UtiliCorp may find that some entities will not be willing to submit bids that otherwise would have done so.

Third, it is not clear in the RFP what "independent" means in the term "independent third party evaluator". The Staff suspects that when that phrase is followed by "approved by the Missouri Public Service Commission," you are intending to convey that independent means chosen by someone other than UtiliCorp. In this regard, the Staff declines to serve as an independent third party evaluator, select the independent third party evaluator or recommend to the Commission that it approve the selection of an independent third party evaluator. The Staff is willing to discuss with UtiliCorp the criteria critical to having an "independent" evaluator. In this regard, it is not clear what "independent" means when the proposed RFP states that "UtiliCorp reserves the right to reject any or all proposals at its sole discretion." Such phrases that undermine the selection of the winning bid by the third party evaluator need to be removed from the RFP and replaced with the criteria used to determine independence.

Another area of concern is that the RFP does not include a section describing how the proposals will be evaluated and how the contract(s) will be awarded. If only UtiliCorp knows how the proposals will be evaluated, this would appear to provide an advantage to any bid submitted by UtiliCorp. The Staff believes that it would make sense to wait to send out the RFP until after the third party evaluator is hired. Then the independent third party evaluator could write the description of the evaluation method/criteria and could also critique the RFP drafted by UtiliCorp before it is sent out.

A final area that the Staff believes it should comment on is the lack of innovative approaches (e.g. demand-side) reflected in the proposed RFP. If UtiliCorp is interested in allowing some of its retail customers to seek alternative providers of generation, this could also be included in the RFP. (Such an approach would require Commission approval.) If the RFP is to be expanded to solicit innovative approaches, the Staff is more than willing to discuss those approaches with UtiliCorp.

Sincerely,

Michael S Proctor

Michael S. Proctor
Chief Energy Economist
Electric Department
(573)751-7518

Roger W. Steiner
Assistant General Counsel
(573)751-7434

cc: Ryan Kind, Office of the Public Counsel
John McKinney, UtiliCorp United, Inc.
David Elliott, Staff of the Missouri Public Service Commission
Steven Dottheim, Staff of the Missouri Public Service Commission

Martha S. Hogerty
Public Counsel

State of Missouri

Mel Carnahan
Governor

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

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

May 11, 1998

Mr. Frank DeBacker
VP – Fuel & Purchased Power
UtiliCorp United, Inc.
10750 East 350 Highway
P.O. Box 11739
Kansas City, MO 64138

Dear Mr. DeBacker:

Your April 7, 1998 letter requested comments from OPC and the Commission Staff regarding the Request for Proposal (RFP) that UtiliCorp intends to issue on May 29. Public Counsel appreciates the opportunity to comment on the RFP process that UtiliCorp intends to use to meet resource needs in the years 2000 and 2001. We are generally supportive of using RFPs to meet future resource needs.

The main concern that Public Counsel has with the current RFP is the provision in Section I that allows UtiliCorp to submit an EWG proposal in response to the RFP. Given the current uncertainties about what regulations and market structure are likely to arise in the electric industry, OPC does not believe that UtiliCorp should be acquiring an ownership interest in additional generating facilities that are located in the same market where it owns and operates electric distribution and transmission facilities. The comments below all pertain to areas of special concern with the RFP that would only apply if UtiliCorp continues to allow itself (or an affiliated corporation) the opportunity to bid on the RFP.

Public Counsel shares the concerns that were expressed by the Commission Staff in its May 1, 1998 letter regarding having personnel from the same corporation submit a bid while at the same time allowing them to issue and evaluate the bid. OPC would have the same concern even if the personnel involved worked for separate affiliates that had ownership ties.

The Staff pointed out a valid and important concern when they stated that "if there is an appearance of UtiliCorp providing an advantage to its own bid, UtiliCorp may find that some entities will not be willing to submit bids that otherwise would have done so." The Staff's opposition to getting involved in the process of selecting or recommending the selection of a third party evaluator makes this approach even more questionable since a third party evaluator would need to be perceived as truly independent if UtiliCorp chooses to submit its own EWG proposal.

Another concern mentioned by the Staff in its May 1, 1998 letter was that the RFP lacks "a section describing how the proposals will be evaluated and how the contract(s) will be awarded." OPC supports the Staff recommendation to hire a third party evaluator before sending out the RFP so the evaluator could critique the RFP and describe the evaluation method/criteria to be used. Public Counsel would appreciate being included in any discussions between the Company and the Staff regarding the RFP process.

Sincerely,

Ryan Kind

Ryan Kind
Chief Utility Economist
(573) 751-5563

J.B. Coffman MK

John B. Coffman
Senior Public Counsel
(573) 751-5565

cc:
John McKinney, UtiliCorp United Inc.
Mike Proctor, MO PSC Staff
Roger Steiner, MO PSC Staff
Martha Hogerty, MO OPC

UtiliCorp United
**EnergyOne**

May 21, 1998

Mr. Ryan Kind
Chief Utility Economist
Office of Public Counsel
Harry S. Truman Bldg.
P.O. Box 7800
Jefferson City, MO 65102

RE: Missouri Public Service Request for Proposal

Dear Mr. Kind:

Enclosed please find the final copy of the Request for Proposal (RFP) for Missouri Public Service (MPS). The RFP will be issued today, May 21, 1998.

Per the comments received from your office and the staff of the Missouri Public Service Commission (MPSC), UtiliCorp United Inc. will not submit a bid in response to the RFP. In order to assure all stakeholders that the process is equitable, we are having all proposals submitted to Burns & McDonnell who will record the receipt of and open all proposals.

You will note that we have extended the solicitation period an additional two years. All proposals for the two additional contract periods must include buyout provisions which would allow MPS to terminate the contract for changes in either the wholesale or retail markets.

Thank you for your input.

Sincerely,

Frank A. DeBacker

Frank A. DeBacker
Vice President, Fuel & Purchased Power

Enclosure

cc: John McKinney
Melissa Klote

UtiliCorp United

EnergyOne

May 21, 1998

Mr. Mike Proctor
Chief Energy Economist
Electric Department
Missouri Public Service Commission
P.O. Box 360
Jefferson City, MO 65102

RE: Missouri Public Service Request for Proposal

Dear Mr. Proctor:

Enclosed please find the final copy of the Request for Proposal (RFP) for Missouri Public Service (MPS). The RFP will be issued today, May 21, 1998.

Per the comments received from your office and the staff of the Office of Public Counsel, UtiliCorp United Inc. will not submit a bid in response to the RFP. In order to assure all stakeholders that the process is equitable, we are having all proposals submitted to Burns & McDonnell who will record the receipt of and open all proposals.

You will note that we have extended the solicitation period an additional two years. All proposals for the two additional contract periods must include buyout provisions which would allow MPS to terminate the contract for changes in either the wholesale or retail markets.

Thank you for your input.

Sincerely,

Frank A. DeBacker
Vice President, Fuel & Purchased Power

FD:[illegible]

Enclosure

cc: John McKinney
Melissa Klote

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

**Issued: May 22, 1998**

## A. General

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

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

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

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

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

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

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

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

## B. Contract Capacities and Periods

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

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

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

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

**Table 1: MPS Capacity Need**

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

### C. Point(s) of Delivery

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

### D. Capacity Pricing

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

### E. Energy Pricing

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

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

On peak/off peak price
Monthly price
Resource heat rate

Constant price
Index price
Resource variable O&M costs

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

## F. Buyout Option

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

## G. Transmission

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

## H. Scheduling

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

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

## I. Availability

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

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

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

## J. Contact

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

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

Power Supply RFP List

J. Craig Baker
Interconnection Agreements & Marketing
American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
614-324-4570 Main No.: 614-223-1000
Fax: 614-223-1823
Email: j.craigbaker@AEP.com

Robert Vinegra
Bulk Power Market Manager
Public Service Electric & Gas Company
80 Park Plaza, T21
Newark, NJ 07102
973-430-5211 Main No.: 973-430-7000 Fax: 973-623-9352
Email: rvinegra@pseg.com

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1901 Chouteau Avenue
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314-554-3807 Fax: 314-554-4679
e-mail: james_c_moore@amer.com

Randall J. Piehler
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CoGen Development Company
150 West Jefferson Avenue
Detroit, MI 48226
313-256-5857

Maureen Borkowski
Manager of Energy Services
Union Electric Company
1901 Chouteau Avenue
P.O. Box 149
St. Louis, MO 63166
314-621-3222 Fax: 314-554-4075

Thomas L. Dobson
Coastal Gas Marketing Company
P.O. Box 1087
Colorado Springs, CO 80944
719-520-4606

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Manager, Resource Acquisition
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502-627-2109 Fax: 502-627-3613

Jack Mayson
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Bill Mohl
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CoEnergy Trading Company
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313-963-3251 Fax: 313-256-5739

Mike Martin
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e-mail: mikema@swps.com

Paige Morey
Southern Company Energy Marketing
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Atlanta, GA 30338
770-821-7447

Dan Gordon
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39 W. Lexington Street
Baltimore, MD 21201
*410-234-7858 Fax: 410-234-7858*
e-mail: dgordon@powersrc.com

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145 Church Street
Marietta, GA 30060
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Sherry Perchik
NP Energy Inc.
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101 S. Fifth Street
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John Catlin
Manager of Power System Operations
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722 N. High School Road
Indianapolis, IN 26214
317-480-2842 Fax: 317-243-6416
e-mail: johnc@wvpa.com

*Tamara Walden*
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P.O. Box 2848
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918-588-3603 Fax: 918-594-1530
e-mail: walden_tamara@wes.twc.com

Sheila Byrne
Kansas City Power & Light Company
P.O. Box 418679
Kansas City, MO 64141
816-654-1218 Fax: 816-654-1476
e-mail: slb2395@KCPL.com

Joe M. Simmons
Manager of Bulk Power
The Empire District Electric Company
P.O. Box 127
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Steven T. Svec
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David D. Rich
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Thomas A. Imbler
Manager, Bulk Power Marketing
Western Resources
818 South Kansas Avenue
Topeka, KS 66601
913-575-1594 Fax: 913-575-6010
e-mail: tom_imbler@wstnres.com

Myra Rivera
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UTILICORP UNITED
ENERGYONE

August 4, 1998

Mr. Mike Proctor
Assistant Manager
Federal/State Projects
Missouri Public Service Commission
310 West High Street
Jefferson City, MO 65101

Mr. Ryan Kind
Chief Utility Economist
Office of Public Counsel
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PO Box 7800
Jefferson City MO 65102

**RE: Reissue of the Missouri Public Service Request for Proposal**

Dear Gentlemen:

On April 7, 1998 Missouri Public Service (MPS) submitted a draft Request for Proposal (RFP) for power supply resources to Staff and the OPC. MPS issued that RFP on May 22, 1998 and bids were received on July 17, 1998. Responses were disappointingly few and the costs alarmingly high.

Burns & McDonnell is in the final stages of evaluating the proposals and will finish their work within the next few weeks. At this time, it is MPS' opinion that its customers and the Company would be better served if MPS were to contract for its additional capacity and energy needs for the 12 months beginning June 1, 2000; and to construct a ~500 MW combined cycle power plant to meet the major portion of MPS' power supply needs for the period beginning June 1, 2001.

MPS plans to discuss the results of the RFP process and its implementation plan for additional resources at our August meeting which is tentatively set for August 24th.

In the event that the Staff and the OPC are of the opinion that:

- MPS should reissue the RFP for resources for 2001 and beyond; and that,
- MPS should submit a formal proposal in response to the RFP; and that,
- All proposals should be evaluated by an independent third party

MPS is submitting the enclosed draft RFP for review. The purpose for submitting the revised RFP for Staff and OPC review at this time is so that MPS will be in position to issue the revised RFP in late September if it is deemed prudent to do so.

Please note that the RFP is for unit contingent resources and the length of the contract term now extends to May, 2007.

Please call me at (816) 936-8639 with any comments, suggestions or questions.

Sincerely,

Frank A DeBacker

Frank A. DeBacker
VP - Fuel & Purchased Power

Attachment

cc: John McKinney UCU w/ attachment

# Request for Proposals
for
# <u>Unit Contingent Capacity & Energy</u>
for
# Missouri Public Service

**Reissued: September 21, 1998**

## A. General

On May 22, 1998, UtiliCorp Energy Group issued a Request for Proposal (RFP) on behalf of Missouri Public Service (MPS), a division of UtiliCorp United Inc. (UCU). Proposals were due on July 17, 1998. In late June, the price for wholesale electric energy skyrocketed to levels of over one hundred times the cost of production. The rapid run up in prices and accompanying market uncertainty reduced the number of responses and produced unrealistically high prices in the responses that were received to the original RFP. In addition, some of the proposals that were submitted were subsequently withdrawn..

Due to the above, UtiliCorp Energy Group finds it necessary to reissue the RFP.

Prospective bidders are advised that based on what it considers to be the high prices currently being quoted for resources, UCU intends to submit a proposal in response to this RFP. UCU's proposal will take the form of an Exempt Wholesale Generator and will be responsive to requirements of this RFP. In order to assure that all proposals are evaluated on a fair and equitable basis, UCU has retained Burns & McDonnell to evaluate all responses (including UCU's) to this RFP.

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

The following RFP is for intermediate load, **Unit Specific Capacity and Energy** resources.

UCU expects to dispatch the unit(s) as intermediate/peaking capacity with annual capacity factors ranging from a low of 30 - 50 percent in the early years to a high of 60 - 70 percent in the later years.

**Unit Specific** means the successful bidder must dedicate a specific generating unit(s) that will provide the capacity and energy requested. For existing units, the unit's name, location and the transmission system to which it is connected must be stated in the proposal. Similar information for new units must also be provided.

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

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

Proposals shall be marked confidential and three copies shall be sent to Kiah Harris at the following address. Proposals must be received no later than 5:00p.m. C.D.S.T., November 13, 1998.

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

## B. Contract Capacities and Periods

Proposals are requested for unit contingent capacity amounts shown in Table 1. UCU expects to dispatch the intermediate capacity portion at annual capacity factors ranging from 40 - 80 percent with the lower capacity factors occurring in the early contract periods. Peaking Capacity will be dispatched at annual capacity factors of less than 25 percent.

Proposals for contract periods beginning June 1, 2003 must include a buyout option. The price of the option shall be stated in $/MW-mo.

**Table 1: Capacity Need**

| Contract Period | | Int. Capacity Amount (MW) | | Peak Capacity Amount (MW) | |
|---|---|---|---|---|---|
| From | To | Min | Max | Min | Max |
| 6/1/2001 | 5/31/2002 | 320 | 350 | 90 | 90 |
| 6/1/2002 | 5/31/2003 | 360 | 380 | 90 | 100 |
| 6/1/2003 | 5/31/2004 | 390 | 410 | 100 | 100 |
| 6/1/2004 | 5/31/2005 | 420 | 440 | 100 | 110 |
| 6/1/2005 | 5/31/2006 | 450 | 490 | 110 | 120 |
| 6/1/2006 | 5/31/2007 | 460 | 530 | 120 | 130 |

## C. Point(s) of Delivery

The Point(s) of Delivery shall be the interconnection point(s) of the resource with the local transmission system. UCU will provide the necessary transmission to deliver the capacity and energy to MPS.

## D. Capacity Price

The Capacity Price shall be given at the Point(s) of Delivery and **must** be stated in $/MW-mo, fixed for each year of the contract term.

## E. Energy Pricing

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

*Bidders may propose a variety of energy pricing methodologies which may include, without limitation, the following elements:*

| | | |
|---|---|---|
| On peak/off peak price | Constant price | Monthly price |
| Index price | Resource heat rate | Start up cost |
| Variable O&M costs | | |

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

*UCU prefers an energy pricing methodology which would allow it the maximum flexibility. To this end, UCU proposes that, for natural gas* fueled resources, UCU assume total responsibility for supplying the fuel necessary to generate the energy supplied under the contract and pay the supplier its variable O&M, start up costs, etc. Under this concept, the supplier would provide the appropriate data and guarantee the heat rate curve, variable O&M costs, start up costs, etc. of the unit(s).

## F. Buyout Option

A buyout option price **must** be provided for each contract period beginning on or after June 1, 2003. The pricing of the option shall stated *in $/MW-mo. that will be applied to the MW amount of the buyout and the months remaining in the contract period subsequent to exercising the* option.

## G. Transmission

Proposals **must** provide the name of the appropriate contact person for the local transmission provider to which the unit(s) is connected.

UCU shall provide the necessary transmission service from the Point(s) of Delivery to MPS.

## H. Scheduling

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

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

## I. Guarantees

Bidders **must** state and define the level of the following performance guarantees where applicable:

| | |
|---|---|
| Availability | Net Capacity |
| Heat Rate Curve | Commercial Operation |
| Start Up Time | |

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

The projected maintenance schedule for the proposed resource(s) shall be included in the bidder's proposal.

## J.. Process Timeline

The total time to complete the bidding process is expected to be four to five months and will generally follow the schedule shown below:

| | |
|---|---|
| Issue RFP | September 14, 1998 |
| Receive Proposals | November 6, 1998 |
| Complete Evaluation | December 4, 1998 |
| Contract Negotiations | December 7 - 31, 1998 |
| Execute Contract | January, 1999 |

## K. Contact

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

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

# UTILICORP UNITED INC.

# MISSOURI PUBLIC SERVICE

# 1998-2003
# PRELIMINARY
# ENERGY SUPPLY PLAN

**August 24, 1998**

# Table of Contents

# 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%<br>Construction Costs: 2.5%<br>O&M Costs: 2.5% |
| Cost of Capital | Debt: 50% @ 7.0%<br>Equity: 50% @ 11% IRR<br>Discount Rate: 10% |
| Fuel Price Escalation (1994-2013) - Real 2.50% | Natural Gas: Real + 0.50%<br>PRB Coal: Real - 0.50%<br>Hanna Coal: Real - 0.50% |
| Reserve Margin | 13.0% Reserve Margin |
| Financial Data | Federal Tax Rate - 35%<br>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.

abundant supply of low-cost energy supplied by its existing resource base which is 64% coal-fired base load generating capacity.

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:

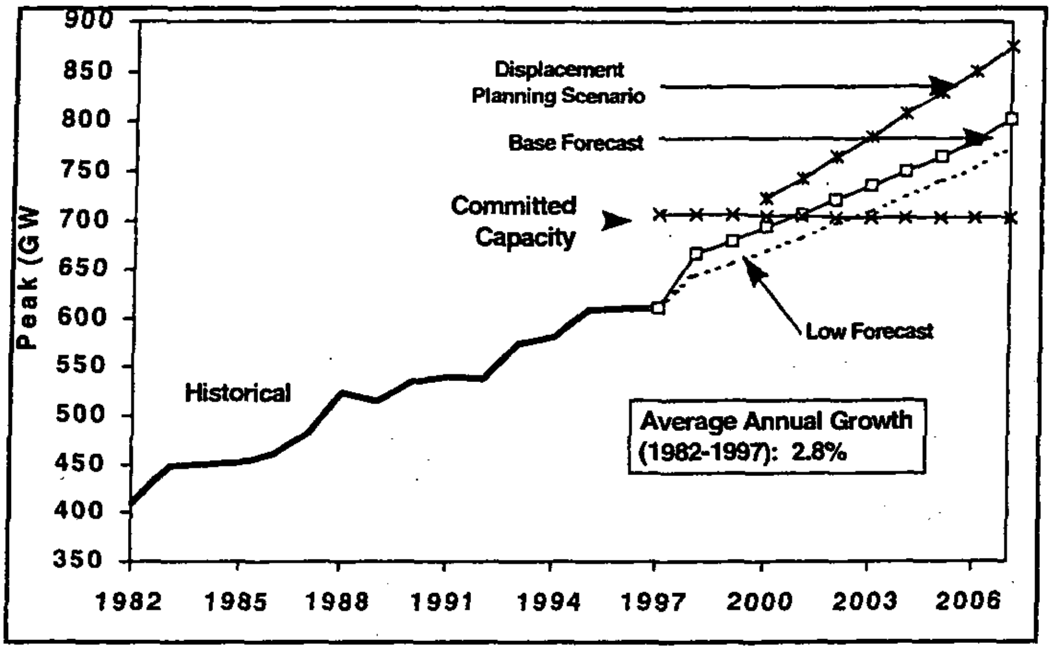
- Negotiate extension of the existing lease agreements on the Greenwood combustion turbines.
- Secure short term capacity to meet MPS' capacity needs thru 2000.
- Pursue the construction of a 500 MW combined cycle unit proposed with an in service date of June 1, 2001.

## 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

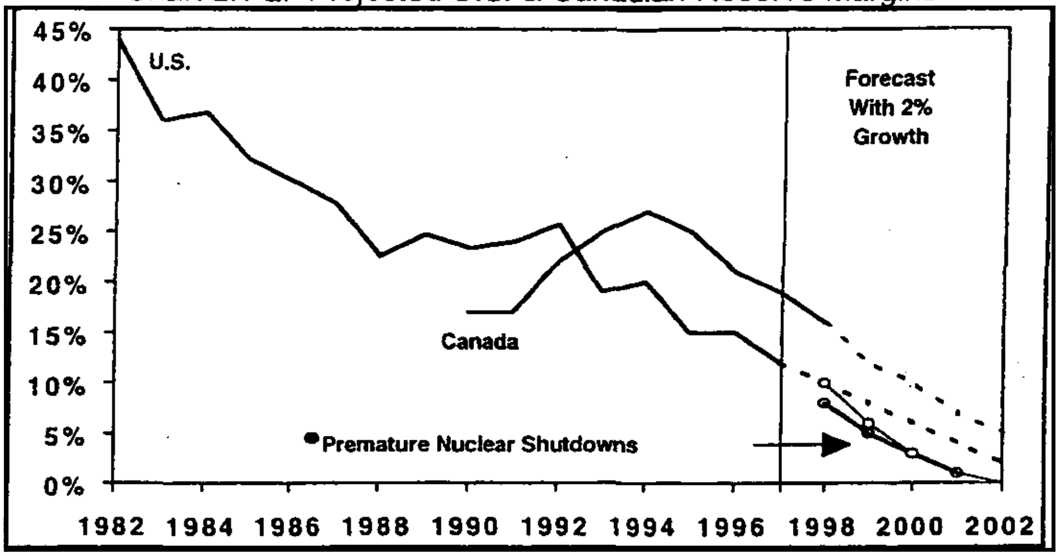



Table 2.1-3: Projected U.S. Regional Reserve Margins

| 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 |

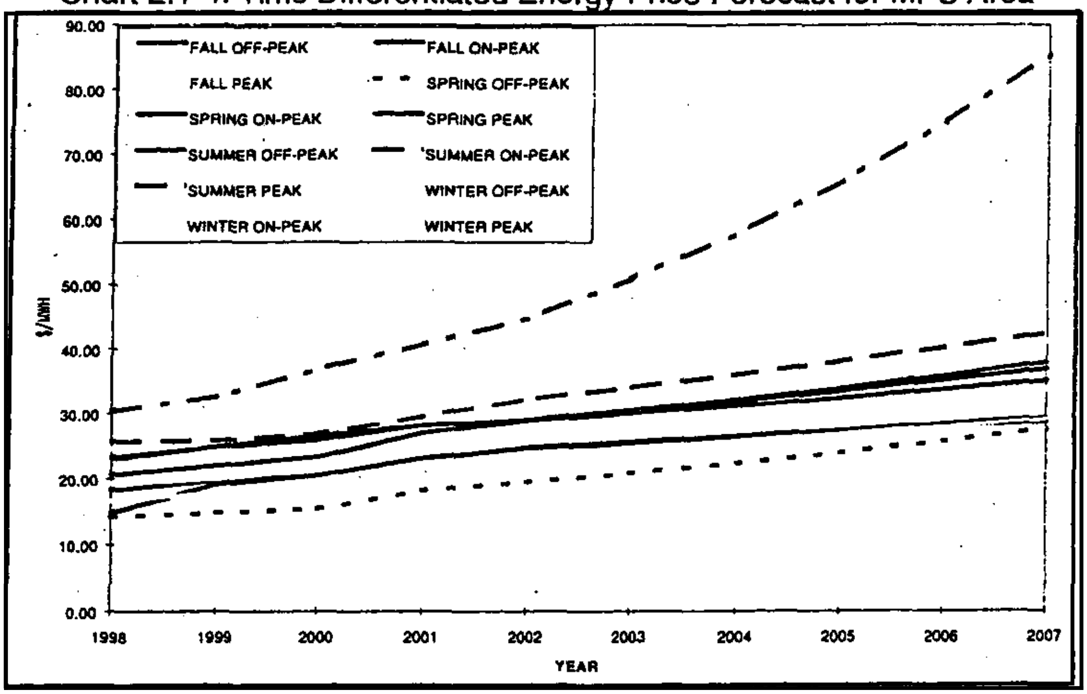
*With Premature Nuclear Shutdowns (NS)
**Region also includes inefficient Fossil capacity with potential for displacement.

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.

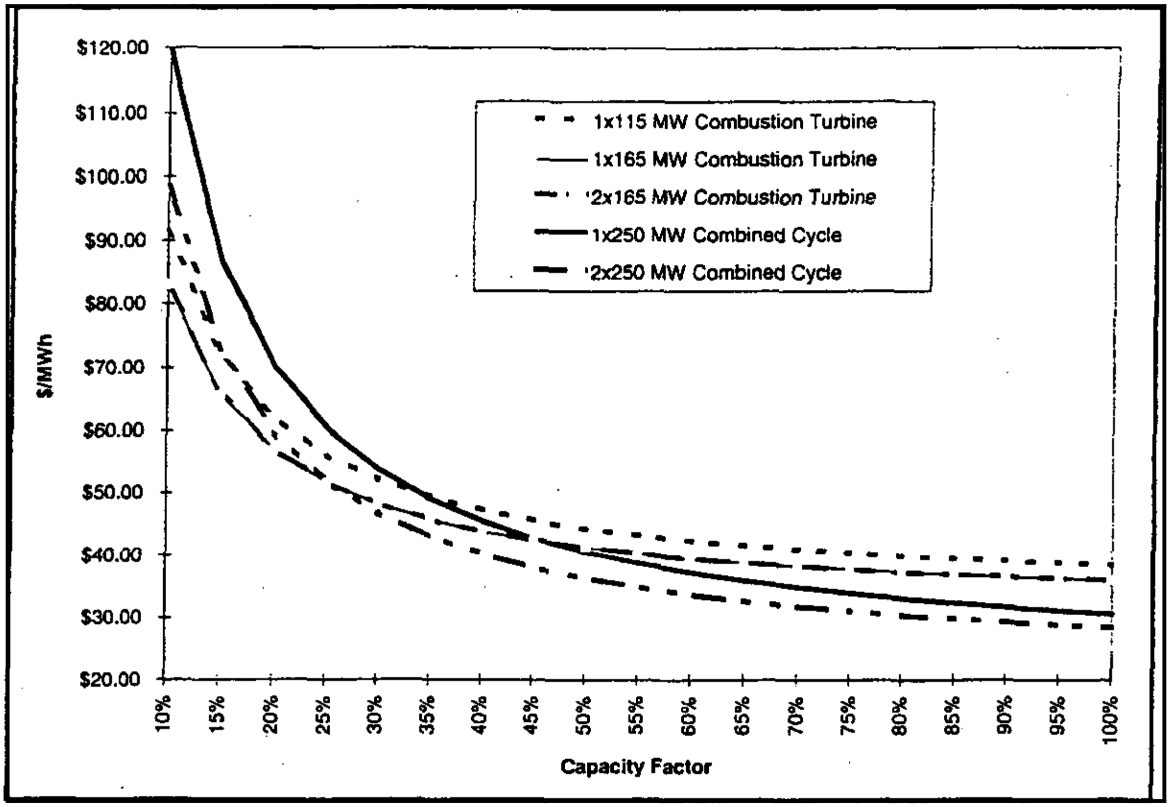
## 4.4 Resource Analysis

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.

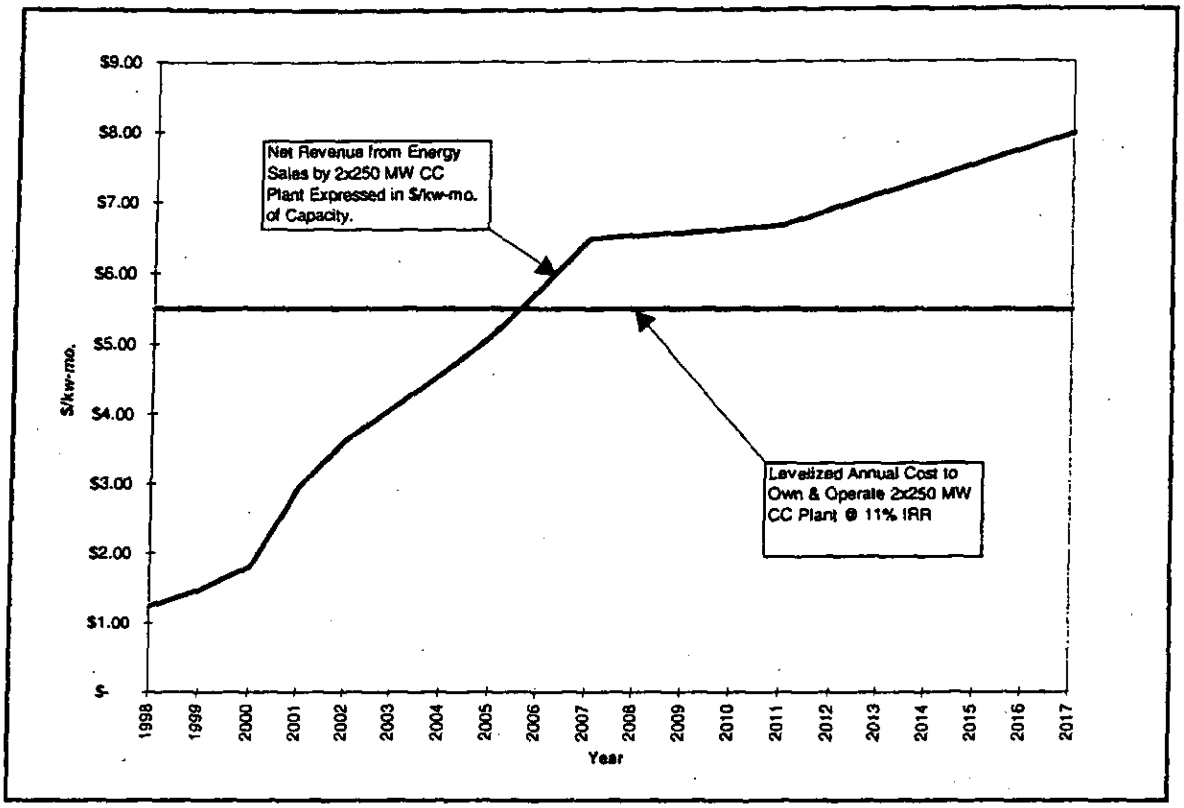
Chart 4.4-1: "All In" Production Cost vs. Load Factor
for five Supply Alternatives




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

## Table 2 (Cont.)
## Case 4b Description

| Case 4b | | Evaluation Period | | | |
|---|---|---|---|---|---|
| | | June, 2000 to May, 2001 | June, 2001 to May, 2002 | June, 2002 to May, 2003 | June, 2003 to May, 2004 |
| **Capacity Need (MW)** | | 255 | 405 | 440 | 480 |
| | | | | | |
| **Offered Capacity (MW)** | | **Capacity Utilized (MW)** | | | |
| LS Power | 540 | | | | |
| UCU | 500 | | | | |
| Aquila 1a | 100 | 100 | | | |
| Aquila 1b | 75 | 75 | | | |
| Aquila 3 | 100 | | | | |
| SPS A | 75-100 | 75 | | | |
| SPS Peak | 25 | 25 | | | |
| Basin | <=100 | | | | |
| NP Energy | 100 | | 100 | 100 | 100 |
| 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 | $ 270,450,646 | $ 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 (Partial Requirement) | 75 | 348,547 | $ 16,082,792 | | | | | | |
| | (Peaking Capacity) | 25 | 10,849 | $ 1,720,933 | | | | | | |
| | Unit-Contingent Purchase | 55 | 12,628 | $ 3,126,081 | | | | | | |
| | 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 | $ 1,646,199 | | | | | | |
| | SPS Option A (Partial Requirement) | 75 | 348,173 | $ 16,074,017 | | | | | | |
| | (Peaking Capacity) | 25 | 11,105 | $ 1,728,457 | | | | | | |
| | Unit-Contingent Purchase | 55 | 12,228 | $ 3,110,389 | | | | | | |
| | Sales | | -9,294,721 | -$229,989,146 | | | | | | |
| Case 3 | | | | | $ 258,759,280 | -$115,277,263 | $ 292,881,747 | $ 436,363,764 | 11.6% | $ 45,196,763 |
| | CP&L | 150 | 272,064 | $ 35,093,650 | | | | | | |
| | Southern | 100 | 2,040,278 | $ 59,696,794 | | | | | | |
| | 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 (Partial Requirement) | 75/100 | 2,732,666 | $ 97,758,915 | | | | | | |
| | (Peaking Capacity) | 25 | 11,069 | $ 1,730,085 | | | | | | |
| | Unit-Contingent Purchase | 55 | 12,622 | $ 3,123,522 | | | | | | |
| | Peaking Contract | | 0 | $ 1,440,000 | | | | | | |
| | Sales | | -4,607,503 | -$115,277,263 | | | | | | |
| Case 4 | | | | | $ 252,834,409 | -$115,370,390 | $ 292,799,355 | $ 430,283,374 | 10.0% | $ 39,096,373 |
| | CP&L | 150 | 271,870 | $ 35,078,240 | | | | | | |
| | Southern | 100 | 2,035,607 | $ 59,600,970 | | | | | | |
| | NP Energy | 100 | 7,611 | $ 18,626,809 | | | | | | |
| | Aquila Option 1a 6/1/2000 - 9/30/2000 | 100 | 168 | $ 4,816,156 | | | | | | |
| | Aquila Option 1b 10/1/2000 - 5/31/2001 | 75 | 0 | $ 1,648,200 | | | | | | |
| | SPS Option A (Partial Requirement) | 75/100 | 2,735,959 | $ 97,822,664 | | | | | | |
| | (Peaking Capacity) | 25 | 10,904 | $ 1,726,183 | | | | | | |
| | Unit-Contingent Purchase | 55 | 12,606 | $ 3,123,748 | | | | | | |
| | Peaking Contract | | 0 | $ 1,440,000 | | | | | | |
| | Sales | | -4,609,397 | -$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 | $ 60,988,698 | | | | | | |
| | NP Energy | 100 | 19,264 | $ 19,001,909 | | | | | | |
| | Aquila Option 1a 6/1/2000 - 9/30/2000 | 100 | 26 | $ 4,801,529 | | | | | | |
| | Aquila Option 1b 10/1/2000 - 5/31/2001 | 75 | 0 | $ 1,648,200 | | | | | | |
| | Aquila 3 | 100 | 131 | $ 24,370,845 | | | | | | |
| | SPS Option A (Partial Requirement) | 75 | 347,040 | $ 16,050,715 | | | | | | |
| | (Peaking Capacity) | 25 | 10,823 | $ 1,721,288 | | | | | | |
| | Unit-Contingent Purchase | 55 | 12,706 | $ 3,128,333 | | | | | | |
| | Peaking Contract | | 0 | $ 1,440,000 | | | | | | |
| | Sales | | -3,061,867 | -$76,232,010 | | | | | | |
| Case 4b | | | | | $ 245,656,954 | -$104,544,438 | $ 299,063,984 | $ 440,176,500 | 12.5% | $ 49,009,499 |
| | CP&L | 150 | 289,141 | $ 35,000,521 | | | | | | |
| | Southern | 100 | 2,095,140 | $ 60,891,338 | | | | | | |
| | NP Energy | 100 | 8,746 | $ 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 (Partial Requirement) | 75 | 348,547 | $ 16,082,792 | | | | | | |
| | (Peaking Capacity) | 25 | 10,848 | $ 1,720,933 | | | | | | |
| | Unit-Contingent Purchase | 55 | 12,828 | $ 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 | $ 4,816,158 | | | | | | |
| | Aquila Option 1b 10/1/2000 - 5/31/2001 | 75 | 0 | $ 1,648,200 | | | | | | |
| | SPS Option A (Partial Requirement) | 75/100 | 2,736,056 | $ 97,824,847 | | | | | | |
| | (Peaking Capacity) | 25 | 10,904 | $ 1,726,183 | | | | | | |
| | Unit-Contingent Purchase | 55 | 12,606 | $ 3,123,748 | | | | | | |
| | Peaking Contract | | 0 | $ 1,440,000 | | | | | | |
| | Sales | | -3,287,595 | -$79,905,446 | | | | | | |
| Case 6 | | | | | $ 249,212,328 | -$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 | $ 18,873,582 | | | | | | |
| | 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 (Partial Requirement) | 75/100 | 2,735,959 | $ 97,822,664 | | | | | | |
| | (Peaking Capacity) | 25 | 10,904 | $ 1,726,183 | | | | | | |
| | 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 | $ 287,934,305 | $ 444,563,188 | 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 (Partial 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

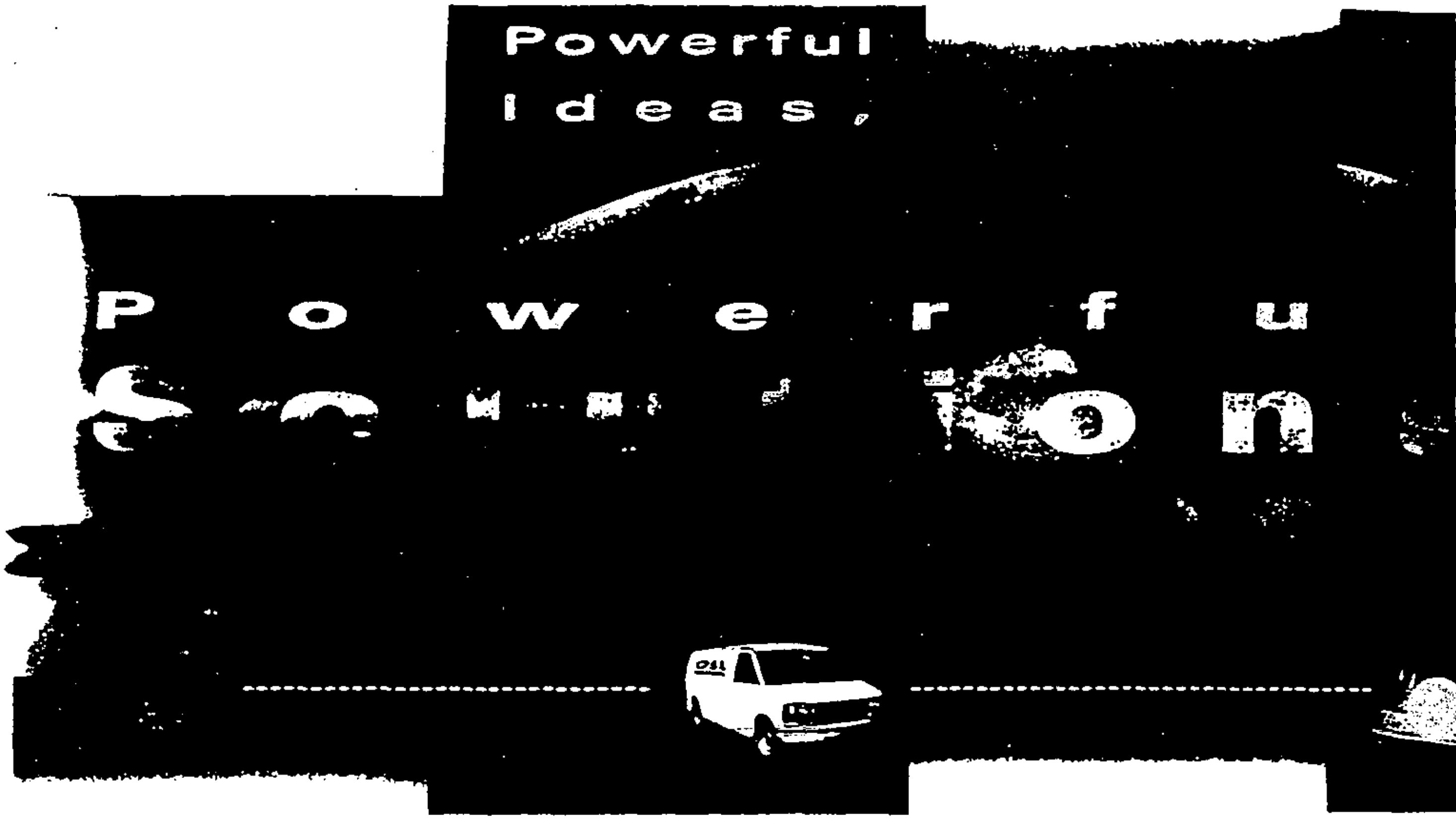
Peaking Contract includes a capacity charge of $4.00/MW-mo. for all capacity deficits

# 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 | | | | | $ 247,482,065 | $ 228,719,801 | $ 476,201,866 | 4.9% | $ 22,182,466 |
| | 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 (Partial Requirement) | 75 | 175,698 | $ 12,420,153 | | | | | |
| | (Peaking Capacity) | 25 | 10,918 | $ 1,723,930 | | | | | |
| | Unit-Contingent Purchase | 55 | 9,776 | $ 3,016,014 | | | | | |
| 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 | $ 77,788,906 | | | | | |
| | Aquila Option 1a 6/1/2000 - 9/30/2000 | 100 | 147 | $ 4,814,017 | | | | | |
| | Aquila Option 1b 10/1/2000 - 5/31/2001 | 75 | 0 | $ 1,648,199 | | | | | |
| | SPS Option A (Partial 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 (Partial Requirement) | 75/100 | 1,422,437 | $ 71,756,138 | | | | | |
| | (Peaking Capacity) | 25 | 10,905 | $ 1,723,749 | | | | | |
| | Unit-Contingent Purchase | 55 | 9,891 | $ 3,019,063 | | | | | |
| | 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 | 87,346 | $ 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 (Partial Requirement) | 75/100 | 1,423,251 | $ 71,770,828 | | | | | |
| | (Peaking Capacity) | 25 | 10,895 | $ 1,724,424 | | | | | |
| | Unit-Contingent Purchase | 55 | 9,921 | $ 3,020,939 | | | | | |
| | Peaking Contract | | 0 | $ 1,440,000 | | | | | |
| Case 4a | | | | | $ 173,655,923 | $ 280,363,477 | $ 454,019,400 | 0.0% | $ - |
| | CP&L | 150 | 128,230 | $ 30,595,187 | | | | | |
| | Southern | 100 | 1,272,189 | $ 43,749,960 | | | | | |
| | NP Energy | 100 | 19,468 | $ 19,007,529 | | | | | |
| | Aquila Option 1a 6/1/2000 - 9/30/2000 | 100 | 26 | $ 4,801,529 | | | | | |
| | Aquila Option 1b 10/1/2000 - 5/31/2001 | 75 | 0 | $ 1,648,200 | | | | | |
| | Aquila 3 | 100 | 131 | $ 24,370,645 | | | | | |
| | SPS Option A (Partial 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 | 847,710 | $ 51,208,572 | | | | | |
| | SPS Option A (Partial Requirement) | 75 | 175,698 | $ 12,420,153 | | | | | |
| | (Peaking Capacity) | 25 | 10,918 | $ 1,723,930 | | | | | |
| | Unit-Contingent Purchase | 55 | 9,776 | $ 3,016,014 | | | | | |
| | Peaking Contract | | 0 | $ 1,440,000 | | | | | |
| Case 5 | | | | | $ 191,200,852 | $ 278,177,382 | $ 469,378,234 | 3.4% | $ 15,358,834 |
| | CP&L | 150 | 125,345 | $ 30,504,582 | | | | | |
| | Aquila Option 3 | 100 | 131 | $ 24,370,645 | | | | | |
| | 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 (Partial 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 | $ 24,377,587 | | | | | |
| | 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 (Partial 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 | $ 24,377,587 | | | | | |
| | 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 (Partial 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

Confidential




# 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 (S/MW-month) | $4690 | $4810 | $4930 | $5050 | $5180 |

**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

**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.

# PROPOSAL

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

P.O. 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 |

$764/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

Prices based on 1 MW

| 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 |

*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.

Back to Price Matrix
Back to OASIS

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

Energy

Jack L. Farley, Jr.
Vice President,
Marketing

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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.