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Issues:	*Aries; Cost of Removal/ Salvage*
Witness:	*Cary G. Featherstone*
Sponsoring Party:	*MoPSC Staff*
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MISSOURI PUBLIC SERVICE COMMISSION

UTILITY SERVICES DIVISION

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Missouri Public Service Commission

SURREBUTTAL TESTIMONY

OF

CARY G. FEATHERSTONE

AQUILA, INC. d/b/a AQUILA NETWORKS-MPS (Electric)

CASE NO. ER-2004-0034

Jefferson City, Missouri
February 2004

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Denotes Highly Confidential Information

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the matter of Aquila, Inc. d/b/a Aquila Networks L&P and Aquila Networks MPS to implement a general rate increase in electricity.	)))	Case No. ER-2004-0034

AFFIDAVIT OF CARY G. FEATHERSTONE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Cary G. Featherstone, of lawful age, on his oath states: that he has participated in the preparation of the following surrebuttal testimony as modified on February 27, 2004, in question and answer form, consisting of 69 pages to be presented in the above case; that the answers in the following surrebuttal testimony as modified on February 27, 2004, were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of his knowledge and belief.

Cary G. Featherstone

Subscribed and sworn to before me this 27th day of February 2004.

TONI M. CHARLTON NOTARY SEAL NOTARY PUBLIC STATE OF MISSOURI

TONI M. CHARLTON
NOTARY PUBLIC STATE OF MISSOURI
COUNTY OF COLE
My Commission Expires December 28, 2004

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CARY G. FEATHERSTONE

AQUILA, INC., d/b/a AQUILA NETWORKS-MPS (Electric)

CASE NO. ER-2004-0034

Q. Please state your name and business address.

A. Cary G. Featherstone, 3675 Noland Road, Independence, Missouri.

Q. By whom are you employed and in what capacity?

A. I am a Regulatory Auditor with the Missouri Public Service Commission (Commission).

Q. Are you the same Cary G. Featherstone who has previously filed direct and rebuttal testimony in this proceeding?

A. Yes, I am. I filed direct testimony on behalf of the Staff of the Missouri Public Service Commission (Staff) in this case on December 9, 2003 on the areas of cost of removal / salvage and the Aries Combined Cycle generating unit (Aries or Aries Project), and rebuttal testimony on January 26, 2004 on the areas of merger savings and Aries.

Q. What is the purpose of this surrebuttal testimony?

A. The purpose of this surrebuttal testimony is to address the rebuttal testimony of Aquila, Inc.'s (Aquila or Company) witnesses regarding Aries and Cost of Removal / Salvage. Specifically, I will address certain aspects of the rebuttal testimonies of Company witnesses Keith G. Stamm, Aquila's Senior Vice President and Chief Operating Officer; and Frank A.

DeBacker, Aquila's former Vice President, Fuel and Purchased Power in the area of purchased power and long-term planning of generating capacity requirements for MPS. Staff witnesses Mark L. Oligschlaeger and Michael S. Proctor will also provide surrebuttal testimony on the Aries issue.

My surrebuttal testimony will also address certain aspects of the testimony of Company witness H. Davis Rooney, Director of Financial Management, in the area of Cost of Removal / Salvage. Staff witness Rosella L. Schad will also provide surrebuttal testimony on this issue.

Q. Please describe how you will be referring to Aquila, its divisions and affiliates in this surrebuttal.

A. When referring to the current Aquila corporate structure, I will be referring to Aquila, Inc., the parent company of all Aquila, Inc. subsidiaries and divisions including its operations regulated by this Commission: Aquila Networks-MPS

. Aquila, Inc. was formerly named UtiliCorp United, Inc. (UtiliCorp). I refer to the operating division Aquila Networks-MPS as MPS

.

During the time of the development of the Aries Project, Aquila was operating as UtiliCorp, so I will use either or "Company" To refer to Aquila/UtiliCorp during that timeframe. References to the non-regulated operations of Aquila / UtiliCorp will likely relate to Aquila Merchant Services, Inc. (Aquila Merchant or AMS). There will a variety of companies, corporations, subsidiaries, affiliates, limited liability companies, limited liability partnerships, etc. that will be defined during the course of this surrebuttal testimony.

ARIES COMBINED CYCLE UNIT

Q. What is the Aries Combined Cycle Unit?

A. This unit is a 585-megawatt combined cycle unit located in Pleasant Hill, Missouri in Cass County. It is jointly owned by Aquila and Calpine Corporation (Calpine) through a variety of subsidiaries and affiliates. The Aries Project is made of two combustion turbines rated at approximate 160-megawatts each, two heat recovery steam generators (HRSGs) and one steam turbine generator having approximately 265-megawatts of generating capacity. The fuel source for Aries is natural gas.

Q. Do MPS have any ownership rights to Aries?

A. No. Aries is owned, in part, by Aquila. MPS are operating divisions of Aquila. Aquila has not given MPS any authority to exercise Aquila's ownership rights to Aries. Aquila's ownership rights to Aries are exercised through Aquila and its subsidiaries and partnerships that are affiliates of MPS.

Q. What is the relationship of MPS to the Aries Project?

A. MPS entered into a purchased power agreement (PPA, and also referred to as a purchased sales agreement or PSA) with Merchant Energy Partners Pleasant Hill (MEPPH) on February 22, 1999 to provide:

1) 320 megawatts of peaking capacity and associated energy for the period June 1, 2001 through September 30, 2001;

2) 200 megawatts of capacity and associated energy for the months of January through March for the years 2002 through 2005 and the months of October through December for the years 2002 through 2004; and

3) 500 megawatts of capacity and associated energy for the months of April through September in the years 2002 through 2004 and for the months of April and May in the year 2005.

Q. What is Aquila's ownership share of the Aries Project?

A. Aquila and Calpine each own 50% of the Aries generating facility. Currently Aquila owns its interest in Aries through series of limited liability companies (LLCs) called MEP Investments, LLC (MEP Investments) and MEP Pleasant Hill Operating, LLC (MEP Operating) who are both power marketers authorized to operate by FERC to engage in wholesale electric power and energy transactions at market-based rates. Aquila Merchant Services, Inc. (Aquila Merchant or AMS) is an indirect owner of MEP Investments and MEP Operating. Aquila Merchant is wholly owned by Aquila and was engaged in the marketing of natural gas and electricity to industrial and wholesale customers in the United States as well as Europe. Aquila Merchant currently is engaged in terminating its merchant gas and power marketing business and is presently assigning or terminating its interest in power sales agreements related to Aries and other generating facilities that it owns.

MEPPH is a special purpose limited liability company and is 50% owned by MEP Investments. MEPPH built and operates the Aries Project. Cass County has bare legal title to "owns" the Aries facility and MEPPH leases all rights in the unit from the county.

Calpine has the other 50% ownership of Aries through a similar corporate structure with a series of limited liability companies and subsidiaries. While, for tax purposes, the unit is "owned" by Cass County Aquila and Calpine have the full and complete responsibility to operate the facility and the financial obligations for the Aries Project.

Calpine has an operating agreement through its limited partnership, Calpine Central, L.P., to operate and maintain the Aries generating facility and Aquila Merchant has the responsibility to market the capacity and related energy output of Aries.

BUILDING OF REGULATED GENERATING ASSETS

Q. Starting at pages 8 of Mr. DeBacker's rebuttal testimony he discusses the process Aquila followed in addressing MPS' future capacity needs. Did Aquila/ UtiliCorp pursue building regulated generation to meet the recent capacity needs of its Missouri utility operations?

A. No. Building regulated generation was not an option considered by the Company. Unlike the other three major electric utilities that operate in the State of Missouri, Aquila has not built or added any significant generation since 1983 when it was a partner in the Jeffrey Energy Center. Instead, Aquila has embarked on a disastrous policy of relying entirely on purchased power agreements to meet the capacity needs of MPS. This policy has subjected MPS and its customers to contracts with market-based rates that will affect MPS's ability to economically meet its future capacity needs, well past the current case and into the foreseeable future. Currently, Aquila is examining its future capacity needs once the Aries purchased power agreement expires. To date, Aquila has not committed to build regulated generating assets to meet the capacity needs of MPS and it also has not made any commitment to replace MPS's current purchased power agreement with MEPPH for power from Aries. That agreement is scheduled to expire May 2005.

Q. How did the Aries purchased power agreement come about?

A. In the spring of 1998, MPS issued a request for proposal (RFP) for its power needs in the early years of this decade. It received responses in July 1998 offering to provide MPS power needs through a variety of options from several different entities. As part of this evaluation by MPS, it also examined the option of building and owning itself a 500 megawatt combined cycle unit with a projected in-service date in 2001.

In August 1998, through MPS analysis as well as the independent analysis of Burns & McDonnell, an engineering consulting firm, MPS determined that the least cost option for it was to build the 500 megawatt combined cycle unit.

Q. Did MPS pursue building the 500 megawatt combined cycle unit?

A. Yes. However, Aquila, at some point, assigned the construction project away from Aquila's regulated MPS operations and transferred it to Aquila Power Corporation, Aquila's (UtiliCorp) non-regulated operations later known as Aquila Merchant.

Mr. DeBacker identifies at page 9, line 7 of his rebuttal testimony the chronology of events leading up to the existing purchase power agreement between MPS and MEPPH. Initially, the regulated operations of MPS pursued building the Aries Combined Cycle Unit as an unregulated Exempt Whole Generator (EWG). The studies and analyses performed by personnel of the regulated operations ultimately led to the conclusion that the 500 megawatt combined cycle unit was the least cost option to meet the capacity needs of MPS starting in 2001. This was confirmed by the independent engineering firm, Burns & McDonnell in an August 1998 report to the Company.

In an August 24, 1998 study entitled "UtiliCorp United Inc. Missouri Public Service 1998-2003 Preliminary Energy Supply Plan," the Company independently determined that the construction of a 500 megawatt combined cycle unit was the least cost plan for MPS. Under the Executive Summary Section 1, "Conclusions," the following appears:

> Conclusions
>
> Based on the 1998-2003 supply-side analysis, the least cost plan for MPS consists of executing short term purchase contacts 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 2001-2003 time frame and a majority of its needs thereafter.
>
> The above supply 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.
>
> The ability of combined cycle units to complete 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 [(Aquila/UtiliCorp)]:
>
> 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.

[Source: Schedule 1, Data Request No. 607—1998-2003 Preliminary Energy Supply Plan]

Q. Did Aquila, then operating as UtiliCorp, ever examine the option of MPS building and owning the Aries Combined Cycle Unit as part of its regulated operations?

A. No. At no time during the 1998 time period, did Aquila or MPS ever consider this as an option. Staff is aware of numerous examples, both in the last MPS electric case (Case No. ER-2001-672) and in this proceeding where Aquila has readily admitted that at no time did it consider allowing the regulated operations of MPS to own or control generating units as regulated plant. While the EWG option was pursued by MPS regulated operations, the combined cycle unit was never planned to be part of the traditional regulated operations of MPS, and Aquila never planned for the unit to be included in rate base.

Q. Does Staff consider this a fatal flaw in the Company's analysis to meet the capacity needs of its Missouri retail electric customers?

A. Yes. To not have even considered the option of building regulated generating assets held by MPS to meet the capacity needs of Aquila's Missouri regulated operations is a failure on the Aquila's (UtiliCorp) part and constitutes imprudence. This decision by Aquila (UtiliCorp) has resulted in Aquila's regulated Missouri operations being at the mercy of purchased power agreements priced at market-based rates through May 31, 2005, and likely will cause Aquila to continue to be subjected to market-based rates for the power used by its Missouri regulated operations to supply power to their customers for the foreseeable future.

Q. What is the effect of Aquila's strategy to not build regulated generating assets?

A. Aquila has subjected its MPS operations, along with the customers served by those two entities, to purchased power agreements priced at market-based rates. While the current market rates for purchased power has declined from the high levels of the late 1990s when Aquila entered into the Aries purchased power agreement, Aquila has still not committed to its regulated operations building or owning their own generation as regulated plant. If regulated divisions built their own generation, it would allow them more control over the price of power in the relatively near future and for many years to come.

Q. What is the basis for the Staff's belief that Aquila did not consider building regulated generation to meet its capacity needs in Missouri and, instead, committed to building unregulated generation?

A. Aquila has freely admitted that it never considered building regulated generating facilities to meet the capacity needs of its regulated utility operations in the state of Missouri. Mr. DeBacker (page 9, line 9 DeBacker rebuttal) and Mr. Stamm (page 12, line 18 Stamm rebuttal) both admit in their rebuttal testimonies that this option was never considered by Aquila's regulated operations. In the last rate case, Case No. ER-2001-672, in Data Request 365, Aquila responded that "the Company believes that the current regulatory climate does not warrant the business risks associated with constructing and owning ratebased generating plants."

Also, in an interview with Mr. DeBacker and Mr. Robert Holzwarth (Vice-President and General Manager of UtiliCorp Power Services (UPS)) held on October 28, 2003, Mr. DeBacker stated that it was corporate policy not to consider building regulated generating assets. Mr. DeBacker indicated in the interview that "MPS did not intend to build and include in rate base generating units to supply its power needs. Thus, Aquila (UtiliCorp) through its regulated MPS division never considered building generating capacity as a regulated unit" (Highly Confidential Schedule 2-5)

Q. Did Aquila provide a reason for why it never entertained the option of building a regulated power plant?

A. Yes. During the aforementioned interview with Mr. DeBacker and Mr. Holzwarth, they indicated there was a corporate policy at Aquila that no new generation would be built as a regulated unit subject to rate basing. The following accurately characterizes the information provided at the October 28, 2003 interviews on this topic of corporate policy:

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[October 28, 2003 interview with DeBacker and Holzwarth, Data Request No. 548; HC Schedule 2]

Q. Mr. DeBacker indicates in his rebuttal testimony that the least cost option that MPS developed for meeting the capacity needs of Aquila's Missouri regulated utility operations was to build the Combined Cycle Unit as an EWG as part of the regulated operations of the Company. Why didn't MPS pursue that option?

A. As Mr. DeBacker indicated in the fall of 1998, the Company decided to create another unregulated corporate entity under its Aquila Merchant subsidiary to build and own generating assets such as the Aries Combined Cycle Unit (page 19 of DeBacker Rebuttal Testimony). While MPS, a regulated division of Aquila, had performed the work required to determine the size and scope of the generating asset needed for the capacity needs of Aquila's Missouri regulated operations, as Mr. DeBacker indicated in his rebuttal testimony, at page 19, line 1 (and also in the October 28, 2003 interview Highly Confidential Schedule 2-5), Aquila upper management transferred that function to the non-regulated operations of Aquila Merchant.

It is interesting to note that the regulated operations of the Company continued to examine the EWG option as late as October 1998. Attached to my rebuttal testimony as Highly Confidential Schedules 3 and 4, are presentations made by Aquila's regulated operations. The presentation made on October 8, 1998 is entitled "Financial Analysis of Supply Options" and the presentation made on October 28, 1998 is entitled "Updated Analysis of Supply Options.". At both of presentations, the regulated operations of the Company presented the EWG option of building and owning the 500 megawatt combined cycle unit. As late as the end of October, the regulated operations of UtiliCorp were still pursuing the generation option that would later become the Aries Project.

However, the option of the regulated operations building the 500 megawatt combined cycle unit was rejected by Aquila's upper management. Other than the statements made in the interview with Mr. DeBacker and Mr. Holzwarth that the Company believed it would be difficult to have the regulated operations build and own the Aries Combined Cycle Unit, the Staff has not seen nor been provided any documentation that would identify the specific reasons why this option was not agreed to by the Company's upper management. In the October 28, 2003, interview, Mr. Holzwarth indicated that upper management decided that it would be too difficult to have the regulated operations create the non-regulated function of building and owning the Aries Unit. The following interview notes, reviewed by the interviewees, accurately describes this:

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[Source: October 28, 2003 interview with Mr. DeBacker and Mr. Holzwarth, Highly Confidential Schedule 2-5]

So, the decision was made to obtain power from other sources. Mr. DeBacker and Mr. Holzwarth indicated that they were not aware of any records documenting the reasons for the MPS EWG option rejection by Aquila's upper management. "Mr. Holzwarth stated that the ultimate decision would have been made by Bob Green and/or Harvey Padawer; however, the consensus opinion of senior management was that a regulated power plant with its potential stranded cost issues was not desirable. Mr. Holzwarth indicated he did not make the decision; he only made the presentation recommending that his group UtiliCorp Power Supply build a generating unit as a non-regulated EWG." [Source: October 28, 2003 interview with Mr. DeBacker and Mr. Holzwarth, Highly Confidential Schedule 2-5]

Q. Did Staff ask who made the decision not to build regulated generating units?

A. Yes. Staff submitted a data request asking the following:

> 1. Why was the decision made by Aquila (formerly UtiliCorp United) not to build and operate Aries Combined Cycle Unit as a "regulated" power plant to be included in rate base? Include in your response all reasons and rationales why this decision was made.
>
> Response: Uncertainty surrounding the deregulation of the electric power industry and the possibility of incurring unrecoverable "stranded costs". Avoiding long term power supply commitments was viewed as a means to effectively mitigate potential "stranded costs" arising from potential retail generation choice.
>
> 2. Provide all supporting documentation relating to and relied on upon in making this decision, including but not limited to reports, analyses, studies, etc.
>
> Response: Compliance with MPS Joint Agreement with MPSC [Missouri Public Service Commission] and Office of Pubic Counsel—approved by PSC in Case No. EO-98-316 on 6/25/98.
>
> Secondary Concern
>
> 1. Inexperience in operating large F-frame combustion turbine generating units and uncertainty surrounding the actual maintenance costs of these machines.

It appears from this response to Data Request No. 302, that Aquila's position is that the Commission's June 25, 1998 Order in Case No. EO-98-316 and the Office of Public Counsel were the basis for the decision by UtiliCorp to create the merchant energy plant known Aries as part of the non-regulated operations of the Company.

Apparently, this project then became assigned to Aquila Merchant and the Aries project was developed as part of the merchant energy partners segment of that operation.

Staff witness Oligschlaeger addresses issues related to stranded costs in his surrebuttal testimony. Staff witness Proctor addresses issues related to Case No. EO-98-316 in his surrebuttal testimony.

Q. Mr. DeBacker attributes to the Commission at page 7, line 9 of his rebuttal testimony responsibility for Aquila not building regulated assets. Does Staff believe that the Commission is responsible for the Company's decision to build Aries as a non-regulated entity?

A. No. As identified on Table 1—Integrated Resource Plans & Joint Agreements, found at page 5, line 10 of Mr. DeBacker's rebuttal testimony, each of the major electric companies operating in this state were given the same direction as Aquila (UtiliCorp) in regard to the Integrated Resource Planning (IRP) process in the late 1990s. Clearly, like Aquila, other companies such as Empire and KCPL received the same type of order to consider changes that might be occurring within the utility industry in the state of Missouri, but that did not deter them from building generating capacity for their regulated operations. It is interesting to note that of the utilities identified by Mr. DeBacker in Table 1 of his rebuttal testimony (page 5), the only utility besides St. Joseph Light & Power that has not built generating capacity for its regulated operations is Aquila. Of course, shortly after the 1997/ 1998 time frame when these Commission Orders were being issued, St. Joseph Light & Power was acquired by Aquila in a merger transaction approved by the Commission in Case No. EM-2000-292.

Q. Who at Aquila made the decision to not to build regulated generating assets to meet MPS capacity requirements?

A. As indicated above cited in the October 28, 2003 interview, Mr. Holzwarth said Mr. Bob Green and Harvey Padawer made the decision not to build regulated generating assets. In response to the Data Request No. 302 the Company identified the following decision makers on that issue:

Bob Green-- Chief Operating Officer supervised by Rick Green

Jim Miller – Leader Business Segment UED (UtiliCorp Energy Delivery)

Harvey Padewar—Leader Business Segment UEG (UtiliCorp Energy Group)

In the October 28, 2003, Staff interview with Mr. DeBacker and Mr. Holzwarth, when asked about who made the decision to build Aries as a nonregulated plant, according to Staff notes of the interview reviewed by the interviewees, they stated:

** **.

Q. Who is Mr. Harvey Padawer?

A. Mr. Padawer was head of Aquila Merchant at the time of the decision relating to what UtiliCorp entity was going to build the Aries Project. Aquila Merchant was engaged in the marketing of natural gas and electricity to industrial and wholesale customers. During the time Mr. Padewar was in charge, Aquila Merchant was starting its merchant energy function, of which the Aries unit was intended to play a major part of that strategy.

Q. Who is Jim Miller?

A. Mr. Miller was head of Aquila's regulated operations, known as the "pipes and wires" part of the business. He was in charge of UtiliCorp Energy Delivery, or the regulated transmission and distribution operations of the Company.

Q. Have other utilities followed a different course than Aquila to meet their power capacity needs since the mid to late 1990s?

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A. Yes. Utilities such as The Empire District Electric Company (Empire), Kansas City Power & Light Company (KCPL) and AmerenUE (Union Electric) have all embarked on building generating assets, and owning and controlling those generating assets as part of their regulated operations. Staff supports this and has encouraged this practice by utilities through the IRP process, as well as various applications that have appeared before the Commission concerning restructuring and reorganizations of the various corporate entities.

In KCPL's application to restructure its corporate operations in Case No. EM-2001-464, a critical element of Staff's concern and, ultimately, the resolution of that application filed with the Commission, was the commitment for KCPL to continue to build and keep regulated generating assets as part of its regulated operations.

Empire has built several generating assets during the 1990's, including a 500 megawatt combined cycle unit that began commercial operation June 2001, just shortly before the Aries unit began its commercial operations in February 2002. All of the generating units at Empire are part of its regulated operations.

Q. What are the examples of other Missouri utilities that have made commitments to build generating units to meet their capacity needs?

A. There have been several successful Missouri electric utilities which have made commitments to build their own generation and treat those units as part of the utility's regulated operations. Empire, KCPL and Union Electric have all made commitments to build generating facilities and treat them as part of their regulated operations. The following identifies the recent generating asset additions for each of these three Missouri electric utilities:

Company	Unit	Capacity	Year Installed
Empire	State Line 1	105 MW	1995
	State Line 2	150 MW	1997
	State Line Combined Cycle	500 MW	2001
	Energy Center 3 & 4	160 MW	2003

Union Electric Company d/b/a AmerenUE has also installed one combustion turbine in 2000 and two combustion turbines in 2002. KCPL installed several generating units: Hawthorn 6, 7, 8 and 9 combustion turbines; converted one of the old Hawthorn 1 through 4 units with Hawthorn 6 unit to combined cycle; rebuilt in 2002 its coal-fired Hawthorn 5 unit after an explosion and in 2003 installed 5 additional combustion turbines in Kansas to serve the regulated operations of KCPL.

Q. Does Staff believe that the Company's only concern with having regulated generating assets in rate base related to "stranded cost?"

A. No. Aquila (UtiliCorp) was looking at the opportunity to earn above regulated rates of return on its investment for power plants built by non-regulated entities. The Company also wanted the opportunity of earn the profits from off-system sales made in the interchange market.

Q. What level of earnings did the Company expect to receive from its investment in Aries?

A. When Aquila (UtiliCorp) was considering the 500 megawatt combined cycle unit as part of an EWG within MPS, the internal rate of return (IRR) expected was higher depending on the financing option considered:

	IRR
Traditional rate basing	** _____ **
EWG	** ______ **
Project Finance	** ______ **

[Source: Highly Confidential Rebuttal Schedule 3-12, Data Request No. 302]

The financial analysis performed by Aquila Merchant identified the internal rate of return expected for the Aries Project of ** ____ ** after-tax to Aquila/UtiliCorp over 30 years based on MEP contribution (Highly Confidential Schedule 3-8; Data Request No. 301).

Either option pursued by Aquila/UtiliCorp, the regulated EWG or the Aquila Merchant, would have given the Company higher returns than under traditional regulated rate base treatment.

Q. How are off-system sales treated in the determination of rates?

A. Off-system sales and related fuel and purchased power costs are included in the ratemaking process; thus, the contribution or margin from these sales are included in rates.

Q. If Aquila built a non-regulated generating unit, would off-system sales made from that unit be available to Aquila's regulated operations?

A. No. Off-system sales made from a non-regulated generating unit would not likely be included in the determination of the revenue requirement.

Q. Has the Company attempted to remove the profit from off-system sales in the past?

A. Even off-system sales profit coming from the regulated generating units have come under attack by Aquila in past rate cases. In Case Nos. ER-97-394 and ER-2001-672, the last two Aquila/MPS electric rate cases, the Company proposed to "share" the profits from off-

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system sales between the shareholders and customers. Aquila proposed the same sharing of off-system sales in its Kansas rate case. Fortunately, both Commissions rejected the Company's sharing proposal and these transactions are still included in the ratemaking process.

Q. Does the Company benefit from off-system sales in the regulated process?

A. Yes. Any off-system sales increase over those set in existing rates are retained exclusively by the Company until the next rate case. Thus, Aquila benefits from off-system sales as part of regulatory lag.

Q. Is it the Staff's view that the opportunities for increased profit motivated Aquila to build the Aries combined cycle unit as non-regulated generation?

A. Yes. More than any concern about stranded cost, the reason why Aquila decided to build the Aries unit as a non-regulated generating unit was to allow it the opportunity to obtain the greater profits through higher returns than would be granted through the regulatory process, and the opportunity to retain off-system sales profits.

Q. Do you have an opinion about MPS' recent resource planning?

A. Yes, from an electric retail customer perspective, it is a failure. The Aries Combined Cycle Unit was conceived and initially designed in 1998 to meet MPS' capacity needs starting in the years 2000-2001. Sometime during the fall of 1998 the project was transferred to Aquila's (UtiliCorp) Aquila Merchant non-regulated operations. Aquila Merchant and a third party were given an opportunity to bid on MPS' capacity requirements. The combined cycle project being considered by MPS' regulated operations as an EWG unit was turned over to Aquila's Merchant. The non-regulated operations of Aquila Merchant, at the request of MPS, were given the responsibility to develop the project through submission of a new bid of RFP. Ultimately, Aquila Merchant, and its affiliate MEPPH were awarded the bid to supply power to MPS.

The Aries Project, in effect, was the combined cycle unit that the regulated operations of MPS first developed as an EWG. The land that Aries was built on was previously owned by MPS and is adjacent to MPS' existing substation. The Company had already commenced to acquire the land to build the combined cycle unit. As the regulated EWG, MPS planned for Aries to be directly interconnected to MPS' electrical transmission and distribution system. Aries was designed with MPS load growth in mind and was the "target" customer of the EWG regulated group. MPS determined that it needed intermediate generating capacity.

The combined cycle project was developed by MPS, but Aquila's upper management did not allow MPS to build the unit. Instead, Aquila Merchant built Aries. This power plant is currently providing service to MPS through a purchased power agreement. The Aries Project could be providing utility service to the Company's regulated operations now, and well into the future, but for the decisions made five years ago by Aquila's upper management. This power plant will not likely be available to serve the needs of MPS' regulated customers in the future because of Aquila's corporate policy of not building regulated generating units. While Aquila is presently considering the capacity needs of MPS once the Aries power agreement ends, it is still very unclear as to what the best solution for the regulated operations will be. The decision making for the best way to replace capacity from Aries is uncertain because of the direction the Company went with its non-regulated operations and the present financial difficulties of Aquila.

Q. What were some of the decisions that Aquila made that cause it to be in the difficult position it now is in to deal with the capacity needs of MPS?

A. The present capacity planning is being influenced by the decision Aquila made to not build and own regulated capacity. That single decision alone causes the current planning process to be influenced by the fact that not only does the Company have to replace 500 megawatts of capacity and associated energy in 2005, but the whole planning mix is changed by virtue of the Company being behind in the build "cycle." Other companies chose to build and now are benefiting directly from those decisions, as difficult as they are. Aquila didn't make those choices in the past and now finds itself playing "catch-up" to develop regulated capacity projects at the very time when it is under tremendous financial pressure. The Company's misjudgment of the market forces, missteps in the non-regulated environment and overall desire to move regulated profits into its non-regulated operations resulted in the failure of Aquila's capacity planning process. The errors in the Company's decision making that most affect the regulated MPS operations are:

- Aquila's decision to not build regulated generation
- Aquila's decision to not allow MPS' regulated operations to build non-regulated EWG
- the desire of the non-regulated operations of Aquila to take full advantage of a volatile power energy market through aggressive trading positions
- the desire of the Company to seek greater profits than what regulated operations typically earn through short term purchased power agreements at market-based pricing
- the desire of the Company to keep the profits from off-system sale transactions
- the financial collapse of Aquila's non-regulated operations resulting in non-investment grade ratings
- Aquila's decision to seek a partner in the development of Aries project

The decisions made by Aquila, which were influenced by the events listed above, will have long-lasting effects on its regulated MPS operations. The Commission should be mindful of these events and fully consider the impacts each has had on MPS when it deliberates on the Aries issue in this case.

Q. Did the Company ever examine building a combined cycle unit as part of the MPS regulated operations prior to the 1998 non-regulated EWG option Aquila's regulated MPS operations pursued?

A. Yes. In reviewing the integrated resource plans that the Company submitted to the Commission and its Staff in May 1995, the Preferred Strategy selected by UtiliCorp for its 1995 Missouri Energy Plan was a combined cycle unit of 206 megawatt capacity with in service 2000, a second combined cycle unit of 206 megawatt capacity in 2001, a combustion turbine of 100 megawatt capacity in 2007 and a combustion turbine of 100 megawatt capacity in 2011. [source: page 1—Summary, UtiliCorp United Inc. Energy Plan May 1995- Submitted to the Missouri Public Service Commission, Data Request No. 572 in Case EM-96-248]

<u>1998 REQUESTS FOR PROPOSALS FOR MPS CAPACITY</u>

Q. Mr. DeBacker states at page 23, line 4 of his rebuttal testimony the total annual capacity payment that of the Houston and Aquila Merchant proposal in 1998 "were significantly lower" than the EWG option of MPS." Is that true?

A. The proposals from Houston and Aquila Merchant can not be compared with the EWG proposal that Mr. DeBacker and Mr. Holzwarth developed. The MPS EWG proposal was for MPS to have the capacity and energy of a 500 megawatt combined cycle plant for the entire year. The $33 million in Mr. DeBacker's rebuttal testimony equates to a $5.50 kw month capacity charge. The entire plant would have been available to MPS to make off-system sales year round.

The Houston proposal was not for a combined cycle unit but combustion turbines with 500 megawatts of summer capacity (June 1 - September 30, 2001 through 2005) with a capacity cost $8.42 kw-month and 200 megawatts of winter capacity (October 1 - May 31, 2001 through 2006) at a cost of $4.21 kw-month.

The Aquila Merchant proposal was also unlike the MPS EWG offer in that it provided 200 megawatts for year round capacity (January 1, 2002 through May 31, 2005) with a final capacity cost of $7.50 per kw-month and 300 additional megawatts of summer capacity (April 1 through September 30, 2005) final capacity cost of $5.90 per kw-month.

The MPS EWG proposal was the lowest cost offer at $5.50 per kw-month for the entire output of the plant. Certainly, the MPS EWG proposal had highest capacity costs at $33 million compared to Houston bid of $23.576 million and the Aquila Merchant bid of $27.766 million. But the MPS EWG proposal provided substantially more energy output.

SALE OF THE ARIES COMBINED CYCLE UNIT

Q. Is the Company currently attempting to sell its ownership share of the Aries Combined Cycle Unit?

A. Yes, in the fall 2003, the Company has made an offer to sell its ownership interest in Aries to Calpine Corporation, the other 50% owner of the Aries project.

Q. Does Staff consider the Aries Combined Cycle Unit to be a valuable asset that the regulated operations should own to meet Missouri's capacity needs?

A. Yes. The Aries Combined Cycle Unit is a 585 megawatt combined cycle unit that can provide intermediate capacity to meet the Company's existing loads and can be used as part of the Company's regulated operation's portfolio of generating assets. The Aries Unit is directly interconnected to MPS electric transmission and distribution system, it is in a the "growth" part of MPS' electric service territory, and it is a unit that was designed with MPS in mind to meet MPS' generation needs into the future. The unit went into commercial operation in February 2002 and, as such, is a two-year-old plant with existing state of the art technology. The land that Aries was built on was sized to build additional generating units and the Company had plans to build those units shortly after Aries went into service. The environmental and air permitting, licensing, gas transportation pipelines, water treatment facilities and piping, are all constructed and providing the necessary functions for Aries to operate for the next several decades. The Company's decision to sell Aries will result in a lost opportunity for the regulated operations to meet MPS' generating capacity needs now and into the future. This is a detriment that results from the imprudent decision making by the Company with respect to the overall capacity planning requirements of Aquila.

Q. Does the Aries Project have value beyond the generating unit itself?

A. Yes. The land site that a generating facility is constructed on has tremendous value to the owners of the project. The development and acquisition of property strategically located in the middle of Aquila's load growth area; permitting and licensing; and the fact that the land is located where it permits direct interconnection with Aquila's existing electrical system all are reasons this site has great value to the Company. These elements are important because the site is sized to accommodate additional combustion turbines. Therefore, if the Company chooses to build future generating assets in its service territory, this site would be very valuable. To give this asset up through a potential sale when the Company needs to replace a substantial amount of capacity in June of 2005 is highly questionable.

Q. Why is the Company in the process of selling its ownership interest in the Aries project?

A. The Company is selling its ownership interest in Aries because it is redirecting its efforts to its core regulated utility operations, including MPS. It is exiting the trading markets and, as such, is disposing of all of its nonregulated operations, including nonregulated generating assets like Aries. Like Aquila Merchant's other non-regulated operations, Aries has experienced financial difficulties. On June 26, 2003, the Aries Partners went into default of the loan that financed the construction of Aries because the MEP partners failed to convert the construction loan to permanent financing. In the summer 2003, the Company considered its options and decided to offer it to sell its ownership share of Aries to Calpine. It entered into negotiations with Calpine throughout the summer and fall of 2003 and reached agreement to sell the Aries Unit in September 2003.

Q. What are the terms of the sale of the Aries Unit to Calpine?

A. The terms of the sale are attached as Highly Confidential Schedule 4 to this surrebuttal testimony. Specifically, Section 4, Highly Confidential Schedule 4-8 identifies the terms and conditions of the proposed sale.

Q. Is there a request for the Commission to open an investigation into the sale of the Aries unit?

A. Yes. On November 14, 2003, Staff filed a motion to open an investigation into the Aries sale. That case has been docketed as Case No. EO-2004-0244.

<u>PURCHASED POWER ENERGY MARKET</u>

Q. Did Aquila believe that the market price of purchased power was going to increase over time?

A. Yes. An analysis performed by the Company to evaluate the 2001 RFP responses submitted to supply capacity and energy needs of MPS past May 2005 identified the forecast of the purchased power costs that was used to assess the various proposals. The Company's forecast for purchased power costs covered the period from 2001 to 2022 and showed a steady and significant increase in these costs during this time frame. In this case, the Company provided a different forecast upon which it relied on to evaluate the existing RFP, which contained forecasts for the purchased power costs for the period 2002-2019. Again, this forecast showed significant increases for the purchased power market. [source: Highly Confidential Schedule 5]

Q. Do you have further support that Aquila believed the market for power costs was expected to increase over time?

A. Yes. In an interview with Mr. Keith Stamm on September 12, 2003, Aquila indicated a belief on the direction of power costs:

> ** ________ **

[Source: Data Request No. 550; Highly Confidential Schedule 6-5; emphasis added]

Q. Would it be prudent to rely on market-based pricing for purchased power costs if there was an expectation that costs were going to increase significantly in the future?

A. No. If there was an expectation that market-based pricing would reflect a significant increase in costs, it would be more prudent to consider building your own

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generating capacity to "lock in" the costs so that you would not be subjected to the ever-increasing costs of the purchased power market.

Q. Would there ever be an advantage to a utility not building its own generating units and relying on purchased power market pricing to serve its regulated customers?

A. Yes, to the extent that a company had both regulated and non-regulated entities and the non-regulated entity owned and operated generating facilities that could sell power to the regulated affiliated company. If the utility believed that the market pricing of power costs was going to rise over time, the utility could build and own non-regulated generating facilities and enter into purchased power agreements with regulated affiliated companies. There would be a direct benefit to the company if the costs could be passed on to regulated customers through rates. The increased power costs would benefit the owner of the generation because they could raise the costs to the regulated entity through market-based rate contracts. This arrangement would benefit the parent company that owned both the regulated utility and the non-regulated generating affiliate because earnings to the parent company would increase. In essence, the forecast of increasing power costs justified the building of the generating facility by the non-regulated entity with the expectation that the increased pricing would be reflected in newly negotiated power contracts. This, of course, assumes that the Company is successful in passing the increase in costs to its regulated customers through purchased power agreements similar to the one that Aquila entered into with the Aries partners.

Q. What are the advantages for regulated utilities to build and operate their own generating facilities?

A. Utilities are able to control the operations of the generating facilities if they own and operate those assets. Utilities will not be subjected to the volatility of the market place with cost increases related to purchased power if they operate their own generating assets. Also, utilities are able to provide a much more reliable source of energy when the regulated company has its generation under its authority. The regulated entity can operate the unit in a prudent and economic manner and can maintain and make capital improvements to prolong the life of this valuable asset.

Q. Did Aquila recognize the advantage in owning generating facilities?

A. Yes. Aquila's non-regulated subsidiary, Aquila Merchant, acquired several generating assets during the time frame Aries was under construction. Aquila believed that the forecast for power costs would be increasing over time, made decisions to "lock in" the cost of owning its own generation, so it could take advantage of the increasing market for power costs. In an October 29, 2003 interview Mr. Max Sherman, a former Aquila Merchant employee and Project Manager during the early development and construction phase of the Aries plant, he discussed the need for generating units:

> ** ____ **

[Source: Data Request No. 549; Highly Confidential Schedule7-8]

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Non-regulated merchant companies would want their own generation so they would not be at the mercy of power pricing "spikes." This was especially important if power had to be delivered through contracts to third parties.

If the regulated entity that did not build and operate its own generating units believed that power costs were going to increase, it would have to enter into purchased power agreements priced at market-based rates. The non-regulated merchant company who negotiated to deliver power to the regulated entity at the escalating market-based contracts benefit if they own and operate their generation assets. In some cases the non-regulated merchant may supply power by either generating or acquiring power through a purchase from another party. The profitability of the non-regulated merchant will depend on the ability to acquire or generate the power at a cost that would be below that which it would receive in revenues. Since Aquila believed there was going to be a significant rise in the power market costs, the non-regulated subsidiary built and acquired generating assets to engage in the open market for power.

Q. Would the same concern exist with the regulated entity concerning owning generating assets?

A. Yes. The approach that Aquila Merchant pursued could also have been followed by the regulated MPS division. For the exact reasons that Aquila Merchant believed it was necessary to own the generating assets, MPS should have built and operated its own generation. This was especially important when you take into consideration that the Company believed that the power market costs were going to rise significantly over time. The decision by Aquila to allow the Aquila Merchant organization to build and acquire generating assets and sell that power through the open market through purchased power agreements like those entered into between the Aries partners and MPS resulted in the situation where Aquila's regulated operations now are subjected to the volatility of the market for power costs. It is clear that Aquila Merchant believed that it could not enter into long-term agreements and be subjected to the whims of the market place in supplying that power, thus causing them to reach a decision to own the generating assets in order to supply those power needs to their non-regulated customers. It should be just as clear that the regulated entity, MPS, would also want to own generating assets in this same situation.

Q. Are there advantages to the utility in owning and operating generating facilities as regulated assets?

A. Yes. Regulated assets are typically put in rate base which, when the units are completed and declared in service, are included in rates allowing the utility a reasonable return on the investment and a recovery over the life of the generating asset through depreciation expense. Thus, a utility is provided some reasonable assurance that the investment in the regulated asset will be fully recovered by its retail electric customers. This provides some reasonable assurance to investors that their asset will be protected through the regulatory process by rate basing the asset. Utility customers benefit by being insulated from rising costs for power during a time when those costs are expected to significantly increase. The customers and the utility owners gain substantial advantages when a company builds and places in service, generating facilities in its regulated operations.

Q. Are there also disadvantages in placing generating assets in the regulated operations?

A. Yes. If there is a belief that there are rising power market costs, a company owning both regulated and non-regulated entities would be at a disadvantage if it put the generating facilities in its regulated operations because it would not be able to shield the profits from the regulated entity. While the regulated entity would have an opportunity to sell the generating capacity in the open market during the period of expected rising power costs, the profits from these transactions are typically included in the ratemaking process. For as long as regulated company can stay out of a rate filing, they will benefit from the increased sales. However, when the company files for rate relief, the power sales would be considered in the rate process. The decision to put generating assets in a regulated entity of a company would cause the non-regulated entity to miss opportunities for profit making by taking full advantage of the increased power cost market. Assets that are in the regulated operations would be held to a typical regulated return which would likely be less than those that would be received by non-regulated entities engaging in profit taking from a rising power market. Aquila believed that it could receive greater returns on its investment dollars by having a non-regulated entity, Aquila Merchant, own the generating facilities and selling the power through purchased power agreements to companies like MPS in the open market through market-based pricing. As the market reflected the increased power costs, the nonregulated entity would also receive the increased revenues resulting in greater-than-regulated returns.

Q. Is there an example where the Company has been subjected to increasing costs through market-based pricing?

A. Yes. In the 1970s, Aquila, then operating as Missouri Public Service Company, built four combustion turbines at its Greenwood Generating Station. Upon completion, the Company sold at book value to financial institutions, all four of the combustion turbines, and received the capacity power through a 25-year lease for each of the generating units. The lease did not allow for any residual value to be passed to the utility entity that originally owned the generating units. Upon expiration of the lease, Aquila reacquired those four combustion turbines at an existing market-based price. In essence, the Company has purchased the same asset twice. The cost to reacquire the assets at the current market is very close to the original cost of the assets when they were new. Thus, Aquila bought 25-year-old generators and paid close to what the original investment was back in the mid-1970s.

Q. Has Aquila used this same approach in its other generating facilities?

A. No. The Company owns several power plants in its regulated companies that were never leased. The coal-fired base load generation owned by Aquila are the Sibley Generating Station, Jeffrey Energy Center and Iatan Generation Station. The Sibley unit first went into service in 1960 with the last unit, Sibley 3, going into service in 1969. The Jeffrey Energy Center began commercial operation in 1978 and the last unit went into service in 1983. The Iatan Generating Station went into commercial operation in May 1980. Sibley and the ownership interest in Jeffrey were acquired by MPS and Iatan became part of Aquila through the merger with the former St. Joseph Light & Power Company. While Sibley is a generating facility that has been in operation for several years, the life of Sibley has been extended beyond the original expected life when it was built through a substantial rebuilds in 1990 and 1993. Thus, customers have enjoyed the low cost generation of Sibley, and will continue to do so for many years to come, when parts of that power plant have become fully depreciated.

If the Sibley generating facility had been leased by Aquila like the Greenwood Units, the Company would have had the benefit of the power generation from Sibley during the term of the lease but would have had to reacquire the power plant through a market-based negotiation with the lessor or owners of the facility. It is likely that Sibley would, through market-based pricing, have cost Aquila's regulated entity, MPS, a substantial sum of money through a buy-back negotiation. There are distinct advantages of owning the assets under a regulated environment.

GREENWOOD ENERGY CENTER

Q. What is the Greenwood Energy Center?

A. The Greenwood Energy Center (Greenwood) is located in the Southeastern part of Jackson County and has four combustion turbine generators, each capable of producing 64-megawatts of electricity. These are peaking generators. The first two units at Greenwood were completed in June of 1975. The third Greenwood unit was completed in the summer of 1977 and the fourth unit was completed in early 1979. While the units are located on a 160-acre site, the actual plant facility occupies the center 35 acres. Originally, the Greenwood units used oil as the fuel source. However, in 1996 all four units were converted to also burn natural gas, and now have dual-burner capabilities. The primary fuel source is natural gas with oil as an emergency or backup fuel. Each unit was originally rated at 45-megawatts yielding a combined total of 180-megawatts for the entire Greenwood Energy Center facility. Subsequently, there have been enhancements to the units, such as the conversion to natural gas as the fuel source, so that now the units have an accredited rating of 64-megawatts each, or a combined capacity of 256-magawatts for the Greenwood generating station as a whole.

Q. How do the Greenwood units relate to the Aries issue?

A. These units illustrate what can happen to power plants that are not owned by the regulated operations and the costs associated with the Company's decision not to place generating plants in rate base. The impacts are long-term and the decision to lease instead of own generation associated with the Greenwood units are very similar to the decision Aquila/MPS made to buy purchased power instead of building and owning the Aries unit.

The costs of the Greenwood units will be greater over their lives since the Company chose to not own and rate base the generating units. Since the four units were leased for 25 years, they were not included in rate base and, in effect had to be re-acquired by Aquila, at prices very close to their original purchase price, in the mid-1970's. If the units had been included in rate base when built, they would have had a reduced net plant value after 25 plus years, and MPS's customers, by the time Aquila re-acquired the units, would have been required to provide less return on investment than they will have to provide in current circumstances. This is because the customers will have to pay for the newly re-acquired costs in rates at about the same costs as when the units were originally purchased. In short, rates will be higher to customers now due to Aquila's re-acquisition of the Greenwood units than had Aquila owned those units from the day they were built.

Q. Does MPS still have a lease relating to the capacity of the Greenwood units?

A. No. Effective with the transfer of the generating assets, the leases with EnergyOne Ventures were terminated. All four of these generators are now considered part of the regulated operations of Aquila's MPS division. As such, the Greenwood units are now part of MPS's plant in service and depreciation reserve.

Q. Have Aquila's costs for re-acquiring the Greenwood units been reflected in the books and records kept by MPS?

A. Yes. The re-acquisition costs for the amounts paid to the financial institution for the Greenwood units are included in the regulated books and records of MPS. The amounts that Aquila re-acquired and transferred for the regulated operations of MPS follow:

Unit	Re-acquired costs	Transferred costs
Greenwood 1	$8,837,500	$8,671,170
Greenwood 2	8,837,500	8,671,170
Greenwood 3	8,900,000	8,897,577
Greenwood 4	6,500,000	6,500,000

[Data Request No. 390]

The reason for the difference in re-acquired price and transferred costs is related to the outstanding debt that Aquila agreed to pay which resulted in a lower cash settlement. (Data Request No. 390.2).

Q. Why are these costs described as "re-acquisition costs?"

A. Aquila, when it was operating as the regulated utility Missouri Public Service Company, originally owned the Greenwood units. It sold them to a financial institution, at Aquila's cost to design, engineer and construct the four units, and then leased the units from the financial institution for a 25-year lease term. Thus, Aquila originally owned the units, sold them in the 1970's, reacquired them in 2000 through its non-regulated operations and leased them to MPS, terminated the lease with MPS in 2003 and, finally, transferred the units to its regulated MPS operations in 2003; hence, the reacquisition of the plant investment made by Aquila over 25 years ago when it was operating as the regulated utility Missouri Public Service Company.

Q. Did Staff include the re-acquisition costs of Greenwood units in plant in service for MPS in this case?

A. Yes.

Q. Why did Staff believe that it was appropriate to include the Greenwood units in plant in service?

A. Staff believes, after examining this issue, that it was left with few options to deal with the concerns it saw with the Greenwood units. Aquila, in its last rate case made an adjustment to reflect a substantial increase to leased payments over those relating to the original 25-year lease. In this case, Aquila transferred the Greenwood units to the regulated operations of MPS and is rate basing them as it would any other generating asset it owns and operates as a regulated unit.

Q. Were the Greenwood units owned by Aquila?

A. Originally, the Greenwood units were owned by Missouri Public Service Company, the predecessor company of Aquila (and UtiliCorp), when they were originally constructed. However, prior to completion, MPS entered into a sale agreement with a financial institution and ownership of the Greenwood Units was transferred to that entity. Upon completion of the sale arrangement, MPS entered into a 25-year lease agreement with the financial institution, commencing with the commercial operation of each Greenwood unit. Each of these leases was for a period of 25 years. The leases for Greenwood Units 1 and 2 terminated in June 2000. The Greenwood Unit 3 lease terminated June 2002 and the Greenwood Unit 4 lease was to originally terminate June 2003. The Company decided to "buy-out" the lease of Unit 4 prior to its termination date. The Greenwood units were sold to the financial institution at the actual "original cost" to construct each unit; thus, there was no gain associated with the sale transaction (Case No. ER-2001-672, Data Request No. 281).

Q. Did the Commission approve the original leases that Missouri Public Service Company entered into with the banking institution in the 1970's?

A. Yes. The Commission approved the original leases for Greenwood Unit 3 in Case No. EA-77-153 and Unit 4 in Case No. EO-79-38. Staff has not located, and the Company has not provided, the Commission Order for Units 1 and 2.

Q. Has the ownership of the Greenwood Units recently changed?

A. Yes. In early 2003, Aquila transferred all four of the Greenwood units to its regulated utility operations, MPS. These units had been assigned to one Aquila's wholly owned subsidiaries until this transfer.

Q. What Aquila entity purchased the units when the leases expired?

A. Upon the termination of the lease in June 2000 for Greenwood Units 1 and 2, Aquila, through a non-regulated subsidiary of the Company called EnergyOne Ventures, acquired the ownership rights to these two units. Aquila then, through its MPS division, entered into a lease arrangement with EnergyOne Ventures for supply of power for a period of five years, with two renewal periods of five years each, resulting in the total term of the lease to be 15 years, if fully exercised.

EnergyOne Ventures was sold in 2002 but the Greenwood units were not part of the sale transaction.

Q. What was EnergyOne Ventures?

A. EnergyOne Ventures was wholly owned subsidiary of Aquila. The Company indicated the following as it relates to EnergyOne Ventures:

> EnergyOne Ventures is an <u>energy</u> services provider created to market commodity and related services to retail and wholesale markets. EnergyOne Ventures primary business activity at this time is selling natural gas commodity in several states, including Missouri. EnergyOne Ventures operates separately and independently from the regulated utilities of UtiliCorp [Aquila].
>
> EnergyOne Ventures, LP, is a Delaware limited partnership formed on September 28, 1999.
> [Source: Case No. ER-2001-672, Data Request No. 479]

Q. Did the lease payments for power supplied to MPS increase when Aquila's affiliated EnergyOne Ventures acquired the Greenwood Units?

A. Yes. The lease payments increased substantially from those of the original lease. The lease payment in the original lease for Greenwood Units 1 and 2 was $1,106,260 on an annual basis. The lease payment "negotiated" between Missouri Public Service and Aquila's EnergyOne Ventures in the first year of the new lease was $3.1 million. This represented an increase of 183% from the original lease. The annual periodic lease payments paid quarterly by Aquila declined throughout the five-year term of the lease with EnergyOne Ventures, as follows:

June 2001 through May 2002	$3.1 million
June 2002 through May 2003	$3.0
June 2003 through May 2004	$2.9
June 2004 through May 2005	$2.7
June 2005 through May 2006	$2.6

[Source: Data Request No. 171---First Amendment to Restated Indenture of Lease, page 7—Schedule 1]

Q. What is the amount that Aquila has included in its case?

A. Aquila made an adjustment to eliminate the annual lease payments charged to Account 550 of $3.9 million. The Company has included the reacquired costs for each of the four Greenwood units in plant in service. The Company has also included the amounts of accumulated depreciation reserve as of June 30, 2003 in its original July 3, 2003 filing and September 30, 2003 in its updated case provide to Staff and the other parties to this case. Staff made the same adjustments to reflect the Greenwood plant investment as of September 30, 2003.

Q. What ratemaking treatment did the Company propose in its last rate case regarding the Greenwood units?

A. In the 2001 rate case, Case No. ER-2001-672, the Company included an annual lease payment of $3.0 million for Greenwood Units 1 and 2, the only units that had been re-acquired at the time. Aquila also included the remaining lease payment amounts from the original lease that had not expired for units 3 and 4 in that case.

Q. What were the original costs of Greenwood Units 1 through 4?

A. Greenwood Units 1 and 2 together were originally built for $11,482,874 in June 1975. Greenwood Unit 3 was originally built for $5,432,798 in June 1977 and Greenwood Unit 4 was originally built for $7,072,860 in June 1979. (Source: Data Request No. 281, Case No. ER-2001-672).

Q. What are the newly acquired costs by EnergyOne Ventures?

A. EnergyOne Ventures acquired Greenwood Units 1 and 2 together for $17,675,000, Greenwood Unit 3 for $8,900,000 and Greenwood Unit 4 for $6,500,000. The following table represents the differences between the original cost and newly acquired costs for each of the Greenwood Units 1 through 4:

Greenwood Units	**Original Cost**	**Newly Acquired Costs**	**Difference**
Units 1 and 2	$11,482,874	$17,675,000	$6,192,126
Unit 3	5,432,798	8,900,000	3,467,202
Unit 4	7,072,860	6,500,000	(572,860)

[Source: Data Request Nos. 281 and 283 in Case No. ER-2001-672]

Q. In the original leases for the Greenwood Units, was MPS responsible for all maintenance and miscellaneous costs to operate those units?

A. Yes. Under the terms of the original lease, MPS was required to incur the costs for maintaining the units, providing property insurance and paying the costs of property taxes, along with any other costs to operate these units. They were also responsible for all fuel costs to operate those units. In addition, MPS was also required to incur all capital costs for the plant additions to each of these four combustion turbines.

Q. In the last rate case, did Aquila, then UtiliCorp, consider acquiring the Greenwood Units 1 through 4 upon the expiration of the original leases through its regulated operating division, then Missouri Public Service and now MPS, and treating the investment as a rate base component?

A. No. There is no indication that Aquila ever considered this as an option. All documents indicate that Aquila's intent was to acquire these units through its wholly owned non-regulated subsidiary, EnergyOne Ventures and to set up a lease between that entity and Aquila's regulated MPS division.

Q. Why did Aquila not consider including the Greenwood Units in rate base as each of the individual leases expired in Case No. ER-2001-672?

A. It appears that Aquila made a corporate decision that its regulated divisions would not build or construct generating units and include those units in the regulated rate base of those entities. In response to Data Request No. 365, Aquila indicated that it "believes that the current regulatory climate does not warrant the business risk associated with constructing and owning rate-based generating plants." It would appear from this statement that Aquila did not consider rate basing the Greenwood Units because of the "regulatory climate" that existed in this state.

Q. Does Staff believe that this is a valid reason for not including Greenwood Units 1 through 4 in rate base for MPS rate base?

A. No. Staff believes, at a minimum, that all of the Greenwood units should be included in MPS's rate base in this and all future rate cases involving MPS.

Q. Did any of the original leases specifically provide that Aquila could reacquire a Greenwood unit or units upon expiration of the lease?

A. Yes, the lease for Greenwood unit 3 did. The leases for the other Greenwood units did not. The Greenwood unit 3 lease provides in the section titled, "Right of First Refusal – Purchase Option" the following:

> The "fair market sales value" of the Unit shall be an amount mutually agreed upon by Lessor and Lessee; provided that if, they are unable to agree upon the fair market sales value of the Unit within 30 days after receipt by Lessor of the notice of Lessee's election to exercise its purchase option in respect of the Unit, either the Lessor or the Lessee may request that such fair market sales value shall be determined by the "Appraisal Procedure." Such "fair market sales value" shall be determined on the basis of, and shall be equal in amount to, the value which would obtain in an arm's length transaction between an informed and willing buyer-user (other than a lessee currently in possession or a used equipment dealer) and an informed and willing seller under no compulsion to sell.
>
> [Source: Data Request No. 171, Case No. ER-2001-672; Greenwood Unit 3 Lease, page 34, Section 20.3, dated May 1, 1977]

Although the "Right of First Refusal" language only appears in the Unit 3 lease, Units 1, 2 and 4 were also acquired by Aquila from the original Lessor.

Q. What is the total of the lease payments MPS made during the 25-year lease for Greenwood units 1 and 2?

A. MPS, during the period from June 1, 1975, through May 2000 incurred a total of $27.6 million in lease payments for the entire 25-year term of the lease. If the units had been placed in rate base, the amount of depreciation expense booked for these units would have been $10.4 million over this same time period. The total lease payments under the expired lease for Units 1 and 2 represents an amount that is 165% more than the depreciation expense that would have been incurred had the units been included in rate base. In addition, if the units had originally been put in rate base by Aquila, then Missouri Public Service Company, instead of leased, the accumulated depreciation reserve would have been $10.4 million at the end of the lease (25 years); thus, there would have only been approximately $1.0 million amount of net plant attributable to Greenwood units 1 and 2 that would be included in MPS' rate base when the original lease ended in June 2000 As a consequence of Aquila's decision to lease rather than own the Greenwood Units 1 and 2, Missouri customers are, in effect, paying for both units again. The reacquisition cost of these units is $6.2 million more than the $11.5 million original cost Aquila incurred to construct the two units in 1975. Thus, the decision by Aquila in the 1970s to lease rather than own the Greenwood Units will, ultimately. be very costly from the perspective of MPS's retail electric customers. A similar analysis and conclusion can be drawn for Greenwood units 3 and 4. [See Schedule 9 for Analysis of Greenwood 1 and 2]

Q. Has the Staff performed an analysis of the impacts of "rate basing" Greenwood Units 1 and 2?

A. Yes. Attached as Schedule 9 is such an analysis. This analysis shows that "rate basing" the Greenwood Units 1 and 2 at the original cost value of $11.5 million would have been far less costly to Missouri retail customers over the estimated useful life of 40 years for these two units. This analysis assumes the life of the units will be at least 40 years (the original lease of 25 years plus the anticipated life of the new lease of up to 15 years). A comparison of the total lease payments with the combined depreciation expense and return components of rate basing the two units, yields the result of almost a doubling of the costs that consumers would have to pay for the capacity of these units. The total of the lease payments appearing on Schedule 2 is $60.5 million while the rate basing costs would have been $32.3 million, a difference of $28.2 million. The cost to the ratepayers of leasing these units is divided between the old non-affiliated lease and the new affiliated lease in effect at the time of Case No. ER-2001-672.

"Old" Lease Payment	$27.6 million
"New" Lease Payment	$32.9 million
Total Lease Payments	$60.5 million

What is interesting is that the "new" lease payments for 15 years were $5.3 million greater than what the "old" lease payments were for 25 years. Of course, the "new" lease for 25-year-old power plants was "negotiated" between Aquila affiliates.

Q. Will MPS customers pay the "new" lease costs?

A. No. As previously explained, Aquila has now decided to place in rate base all of the Greenwood units. Staff is raising the issue of the "new" lease payments because those payments reflected Aquila's position on Greenwood rate recovery in Case No. ER-2001-672, and because it illustrates Aquila's desire to implement market-based pricing of power at every opportunity, to the detriment of its retail electric customers.

Q. Why is leasing the units so much more expensive than "rate basing" them?

A. The rate basing option assumes that the original cost of plant investment is eventually fully recovered from customers. While depreciation expense continues throughout the useful life of the plant, the capital costs (or return on investment) declines. On the other hand, the lease payments MPS would have been required to make under the terms of the newly "negotiated" lease, while fluctuating somewhat, are at a high level in relation to fully depreciated units under the rate basing scenario.

Q. What would have been the difference in rate basing Units 1 and 2 instead of making the lease payments over a 25-year lease period?

A. It is difficult to make an exact and precise analysis, using capital structures and rates of return authorized by the Commission during the period of the lease and comparing that to the lease payments, Staff believes the lease option would, ultimately, be considerably more costly to Aquila's retail electric customers than the rate basing (ownership) option because during the 25-year period, there would have been a continued decline of rate base due to the increase to accumulated depreciation reserve which is used as an offset to the original cost plant investment. In addition, Missouri retail electric customers would have received the benefit of any resulting deferred taxes relating to the Greenwood Units, which are used as an offset to rate base in the ratemaking process. The deferred tax amounts were not available to include in the analysis appearing on Schedule 9, including deferred taxes would have resulted in further savings under the rate basing ownership option.

While Aquila would still be entitled to a return of this plant investment, the revenue requirements associated with rate basing the Greenwood units would continually decline because the recovery of depreciation by the customers would have resulted in increasing accumulated depreciation reserve and in addition, would have also reduced the capital costs using the deferred tax benefits.

Q. Does the Staff have any proposal to effectively undo the effects of the Greenwood units being leased then reacquired instead of being included in rate base when built?

A. No. It is not possible to go back in time and restate for rate purposes what the cost would have been of owning versus leasing the Greenwood Units. However, it is important for the Commission to realize the full imports of the prior leases and the potential to repeat that scenario now and in the future. What Aquila proposed in the last case was to continue to lease the units from an affiliated company to meet MPS capacity needs. These units were reacquired at an amount greater than the original cost of those facilities when they were first constructed in the 1970's. The Company in essence, has begun paying for the units a second time. Since the units have been put in rate base at the re-acquired costs in this case, the customers will be required to pay for this plant investment again over and above the amount had they been placed in rate base from the start of their service lives.

COMMISSION'S APPROVAL OF THE PURCHASED POWER AGREEMENT

Q. Did the Commission approve the purchase power agreement for the Aries Unit?

A. Yes. In Case No. EM-99-369, the Company filed an application with the Commission seeking approval of the purchased power agreement and the EWG status so that it could file with the Federal Energy Regulatory Commission (FERC). This application was filed on March 1, 1999, and the Company requested that the Commission consider it on an expedited basis.

Q. Did the Staff make a recommendation in Case No. EM-99-369 regarding the application on the EWG status and the purchase power agreement?

A. Yes. On April 5, 1999, four weeks after the original application was filed with the Commission, two memorandums were filed with the Commission relating to this case.

Q. Did Staff do an extensive and detailed analysis of this Application?

A. No. Staff did not have sufficient time to provide the Commission the detailed analysis that would have been required to fully evaluate this application.

Q. Did the Company have to have expedited treatment regarding this application?

A. No. While the Company sought expedited treatment in its application, there has been evidence discovered by Staff that Aquila's anticipated timeline for the approval process at FERC and the Missouri Commission was a six-month timeframe. In a presentation made to UtiliCorp upper management on January 5, 1999, the presenter indicated that the application would be filed in early spring with an expected approval by the Missouri Commission in August 1999. That presentation indicated there would be a six-month review process provided to the Commission before Aquila sought FERC approval.

Q. Was the Staff aware of the information relating to the January 5, 1999, presentation made to the senior management of Aquila (UtiliCorp) when it filed its recommendations in Case No. EM-99-369?

A. No.

Q. If Staff was aware that Aquila had planned for the Commission to have six months to review this application, would that have made a difference in the review the Staff would have conducted in considering the request for EWG status?

A. Yes. Staff only had approximately four weeks before it had to submit its recommendation to the Commission regarding Aquila's application, which Aquila submitted March 1, 1999. The scope of Staff's review and its ability to do discovery was virtually nonexistent. The timing of the case which was imposed upon by Aquila (UtiliCorp), greatly hampered Staff's ability to form a detailed and thorough analysis relating to the application. It is clear that Aquila did not need the expedited treatment that it requested from the Commission in order to get approval from FERC for EWG status relating to the Aries project.

Q. How had the Staff planned on performing its review Aquila's application relating to the EWG status?

A. Staff had intended on performing a review for this application similar to the one it performed in a previous application Aquila (UtiliCorp) made to the Commission in Case No. EM-97-395. In that case, Aquila requested to transfer into a separate generating subsidiary, all of the regulated generating assets it held at that time. The regulated assets included Sibley Generating Station, which totaled 523 megawatts, the Gas Turbine Generating Plant near Pleasant Hill, Missouri, known as Ralph Green, having a rating of 94 megawatts, a Gas Turbine known as KCI having a rating of 40 megawatts, UtiliCorp's 8% interest in Jeffrey Energy Center, totaling 175 megawatts, four oil and gas-fired turbine generating units known as Greenwood, totaling 287 megawatts and a lease for the Nevada Generating Unit with 22 megawatts. At that time, UtiliCorp also had separate purchased power agreements with Union

Electric, Associated Electric Cooperative and a seasonal capacity agreement with KCPL which was to go into effect April 1, 1997 and terminate September 30, 1999.

Paragraph 9 of the application in Case No. EM-97-395, states:

> UtiliCorp proposes to create a subsidiary corporation, as yet unnamed but designated presently as UtiliCorp GenCo ("UGC") for purposes of this Application. Upon incorporation of UGC in the State of Delaware, UGC proposes to apply to the Federal Energy Regulatory Commission ("FERC") for a determination that it is an exempt wholesale generator ("EWG"), as that term is defined in § 32 of PUHCA, for the purpose of engaging in the business of owning and/or operating eligible electric generation facilities and selling electric energy at wholesale to other parties, including UtiliCorp. Pursuant to an Agreement of transfer, and such other documents of conveyance as may be required, UtiliCorp will transfer, convey and assign all of its right, title and interest in and to the Generating Assets including associated operating permits and authorities, leasehold interest and purchase power contracts, to UGC and UGC will therefore own and operate said facilities and assume all rights and obligations under the relevant contracts. …
>
> 10. UtiliCorp will enter into a long-term Electric Service Agreement with UGC to purchase from UGC electric energy at wholesale under terms and conditions that will ensure a steady, affordable, and reliable source of electric power for distribution by MPS to its electric utility customers…

Q. What was Aquila (UtiliCorp) requesting from the Commission at the time of its filing in Case No. EM-97-395?

A. The March 21, 1997, filing by Aquila made essentially the same request for all of Aquila's then existing generating assets held by its regulated MPS operations that Aquila made for the purchased power agreement for power from the Aries Project in Case No. EM-99-369 that Aquila filed on March 1, 1999. Paragraph 12 of the March 21, 1997 application relating to the existing generating assets stated:

> Pursuant to paragraph 32(c) and (k)(2) of PUHCA, a state commission having jurisdiction over the retail electric rates of UtiliCorp, such as the Commission, must make specific fact determinations (a) before the FERC will consider the described facilities to be "eligible facilities"

> under the Act, and (b) in advance of UtiliCorp entering into the proposed Electric Service Agreement. Specifically, the Commission must find that it has sufficient regulatory authority, resources and access to the books and records of UtiliCorp and any relevant affiliate or subsidiary such that it may determine that the proposed transaction (including the transfer of the Generating Assets and the execution of the Electric Service Agreement) (1) will benefit consumers, (2) do not violate any applicable state law, (3) would not provide UGC any unfair competitive advantage by virtue of its affiliation with UtiliCorp and (4) are in the public interest. In addition, provisions of § 393.190.1, RSMo require that the Commission make a determination that the proposed asset transfer is not detrimental to the public interest.

Q. Did the Staff have more time to review the EWG application relating to the existing generating assets made in the March 21, 1997, filing by Aquila (UtiliCorp) than it did in Case No. EM-99-369?

A. Yes. UtiliCorp made the filing in Case No. EM-97-395 March 21, 1997. This filing was made at the same time that the Company filed a rate case that was designated as Case No. ER-97-394. The Staff had been reviewing the Company's rates as part of a merger application between UtiliCorp and KCPL that later was rejected by the shareholders of KCPL. Staff had filed a complaint case as a result of its earnings investigation designated as Case Nos. EC-97-362 and EO-97-144. In response to that complaint case, the Company filed its rate case on March 21, 1997, along with the Case No. EM-97-395, which requested the transfer of the electric generating assets to UGC and to create the EWG.

Q. Did Staff support the transfer of Aquila's (UtiliCorp's) electric generating assets to the EWG subsidiary in Case No. EM-97-395?

A. No. In November 1997, the Staff filed extensive rebuttal testimony in opposition to Aquila's (UtiliCorp's) proposal to create the EWG subsidiary and transfer its existing generating assets out of the regulated operations of MPS. Staff had between the March 21, 1997 filing of the application by the Company and the November rebuttal filing, to assess and evaluate the merits of the Company's proposal. Staff did extensive discovery and conducted interviews in conjunction with the ongoing review of the Company's general electric rate increase application in order to make its findings as part of its rebuttal response to the Company's application.

Q. Did the Commission grant the Company's March 21, 1997, application to transfer the electric generating assets to UGC?

A. No. The Company, subsequent to Staff's rebuttal testimony in opposition to the Company's application, decided to withdraw the application and the existing generating assets remained with its regulated MPS operations.

Q. What is the significance of the timing of the application filed in Case No. EM-97-395?

A. Staff was given significantly more time to do its review of that application than it was with respect to the purchase power agreement relating to the Aries project. That application was filed in Case No. EM-99-369 on March 1, 1999. At paragraph 17 of the March 1, 1999, application, Aquila (UtiliCorp) stated:

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

[Application in Case No. EM-99-369, page 6]

Q. Did the Commission grant the Company expedited treatment for this application?

A. Yes. Based on the request by the Company for expedited treatment for the case, the Commission issued an Order on March 5, 1999, directing the Staff "to file its recommendations regarding approval or rejection of UtiliCorp's Application no later than April 5, 1999."

Q. Did UtiliCorp specifically request ratemaking treatment with respect to the March 1, 1999 application in Case No. EM-99-369?

A. No. At paragraph 15 of the application, the Company stated "UtiliCorp understands that an order containing the findings required by the PUHCA with respect to the PSA shall in no way be binding on the Commission or any party to a future rate case to contest the ratemaking treatment to be afford PSA."

Q. With respect to the March 1, 1999, application in Case No. EM-99-369, did the Company create the apparent need for expedited treatment?

A. Yes. Aquila, in its rebuttal filed in this current proceeding, indicates that the Commission approved the EWG status and approved the purchase sales agreement, and clearly understood that the Commission was not granting any ratemaking treatment relating to the Aries purchase power agreement. In essence the Company, through its application and its request for expedited treatment, created the urgency for Commission approval that did not allow the same type of review of the EWG status relating to the existing generation that was filed for in its March 21, 1997, application in Case No. EM-97-395. The Company, by virtue of its request for expedited treatment, has to assume full responsibility for creating the situation that it finds itself in today. It is Staff's belief that the Company made a deliberate and calculated attempt to shorten the Commission's review of the March 1, 1999, Application relating to the Aries purchase power agreement in Case No. EM-99-369, the consequences of which must be assumed by the Company in that no ratemaking treatment was granted for this purchase power agreement, as none was being sought in the March 1, 1999 application by Aquila (UtiliCorp).

Q. At page 4, line 19, of Company witness Keith G. Stamm's rebuttal, he addresses his concern about the Staff's role as a consumer advocate. Does Staff have a concern about the Company's interpretation of Staff's role?

A. Yes. Mr. Stamm states at page 4, that:

> My own view is that over the past several years the Staff has come to assume a role of consumer advocacy instead of the role of attempting to balance the interests of consumers and investors. While the reasons for the increases I mentioned are well-known and unavoidable, Staff's objective seems to be aimed at retaining existing rate levels to the extent possible by offsetting these known increases through aggressive and what I believe to be unjust and unreasonable stances on nearly every other major issue. While political expediency may suggest maintaining rates at existing levels, the impact is to place the burden of increasing costs directly on the backs of shareholders. In the long run, this approach will harm our customers.

It is noteworthy that Aquila, as a corporation has experienced significant failures from its non-regulated operations directly related to the decision of Aquila management which has increased "costs directly on the backs of shareholders." In 2002 alone, Aquila incurred in excess of over $2 billion of corporate losses, all attributed to Aquila's managements decisions to engage in aggressive and what ultimately became "unjust and unreasonable stances" with respect to nonregulated endeavors that ultimately failed the Company and caused great hardship to its shareholders. In 2002, the Company announced the reduction of, and then, the ultimate suspension of dividends to its shareholders, strictly related to the failures of its non-regulated operations. Its investment in Quanta, alone cost the Company a write-off of almost $750 million in 2002. Its trading operations collapsed and as noted in my direct testimony, the Company was obligated to pay substantial amounts relating to tolling agreements for three power plants, including the Aries project, that totaled over the life of the agreements, in excess of $2.1 billion. It has been the Company's aggressive and, at times, seemingly reckless decision-making that has gotten the Company in its present financial condition.

I don't believe that the Company's financials woes, collapse in the stock market and the financial markets assessment of Aquila's credit worthiness to that of non-investment grade financial ratings has anything to do with Aquila's Missouri operations in general, or specifically to regulatory decisions made by the Commission or recommendations made to the Commission by its Staff. Aquila has only to look inward to find the source of its current financial woes.

Q. Has Staff attempted to balance the interests of the Company and the consumers?

A. Yes. Unfortunately, for Aquila, the Company's former attention was solely in the direction of non-regulated operations. This was at the expense of the regulated MPS operations. At no time, in the review of documents and discussions with the Company, was it apparent that the interests of regulated operations of MPS were being looked after by Aquila (UtiliCorp) management or those in charge of running the regulated operations. In all instances relating to the Aries project and relating to the securing capacity during the years 1998 and 1999, is it clear that the Company was focusing its attention solely to the interests of nonregulated operations of the corporation. There is no evidence that anyone from Aquila (then UtiliCorp) was looking out for the long-term best interest of the regulated MPS operations of the Company or its Missouri retail electric customers. Even Mr. DeBacker and Mr. Holzwarth, who were solely responsible for securing the proper generation and capacity needs of the Company's regulated operations, focused their attention exclusively on the interests of the non-regulated operations, although their proposal was to build non-regulated generation as part of the regulated entity of MPS as an EWG. No one, other than the Staff, has focused primary attention on the interests of the regulated operations of the Company. Staff, while it is interested in maintaining the proper capacity mix for its customers and to ensure that the future generation needs of the Missouri operations is being met, has also attempted to ensure that the interests MPS regulated operations has been appropriately and properly considered in generation resource planning decisions.

All the Company's focus and attention was put into the non-regulated operations, first in establishing, creating and developing the nonregulated operations of Aquila (UtiliCorp) and now in the disposition of assets relating to the nonregulated operations. It appears that the regulated operations of MPS have been considered only as an afterthought and it is only after the failures of the non-regulated operations that the Company now has conceded that it is time to focus its full attention back to its core related utility operations. In Staff's view, the Commission should be very concerned about the focus of Aquila's upper management with respect to how it has pursued meeting the generating capacity needs of its Missouri regulated operations, MPS.

Q. How has the Company's inattention to the Missouri-regulated operations of the Company impacted those operations and its customers?

A. In every instance, the Staff knows about with regard to other Missouri electric operations, the companies have pursued meeting their customers' capacity needs through building and owning generating assets. Aquila alone made the decision to pursue purchase power agreements with market-based rates. The decision by Aquila's management to embark on a non-regulated path to meet its capacity needs has put the regulated operations "behind the curve" in the sense of ownership of power production facilities. Empire as a company, and Empire's customers, have enjoyed the benefits of the State Line Combined Cycle since it went into production of electricity in June 2001. Empire and its customers will have the benefit of that unit for many years to come.

Q. Are there advantages to ownership of generating facilities by regulated utilities?

A. The control of generating facilities by utilities is considered very important. Companies believe they can better manage costs for maintenance and reliability of units if they own them. In essence, by controlling the generating unit, the Company is much more in charge of their own destiny. In an interview with Staff on November 14, 2003, Mr. Terry Hedrick indicated that he believed there were "significant advantages in both owning and operating the generation equipment in developing maintenance expertise. If you control / own the equipment, he believes that there are advantages in the areas of costs, manpower and staffing and dispatch flexibility." (Data Request No. 616—Highly Confidential Schedule8-5)

Q. Are there advantages to customers for regulated utilities owning generating assets?

A. Yes. Generally, the costs (revenue requirements) are higher in the early years of ownership. The capital costs of the plant investment require a return (return on investment) and the utility is entitled to a recovery of the investment (return of investment). As the plant investment is recovered through depreciation—the return of investment--, the rate base return required—return on the investment—decreases. At some point in the future, especially if the plant lives are longer than expected, such as in the case of Aquila's Sibley generating units, the customers will have the benefit of the plant while the rate base investment is very low. The return on investment declines which causes the revenue requirements to decline dramatically.

Aquila, by deciding not to build regulated generation in the 1990's, has put the company's customers at risk because there is a substantial amount of capacity that it will have to replace—at least 500 megawatts—once the Aries purchased power agreement expires in May 2005. Aquila made no commitment to build regulated generation for 20 years, unlike every other major electric utility that operates in this state, and now faces the challenge of replacing the Aries capacity in large block of power, at least 500 megawatts.

Empire, KCPL and Union Electric all faced the same uncertain future as Aquila (UtiliCorp). These entities had the very same concerns about stranded investment costs; about deregulation issues; about impacts of retail competition and loss of customers from customer choice issues. Yet, despite all these uncertainties, Empire, KCPL and Union Electric chose to follow a different path then the one Aquila chose. There is no question the success of those companies decisions far outpace the success, or lack of it, that Aquila finds itself in today. One only has to compare the financial results, investment grade of the credit ratings, stock price and dividends paid to its shareholders to see the difference that the choices made by the non-Aquila group in relation to the choices made by Aquila.

COST OF REMOVAL/SALVAGE

Q. Company witness H. Davis Rooney in his rebuttal testimony, page 2, line 18, states that "both the Missouri Code of State Regulations and the Code of Federal Regulations require rate base accounting treatment for net salvage." What is the Company referring to with to Mr. Rooney's rebuttal testimony?

A. What Mr. Rooney is referring to when he sites the Code of Federal Regulations is the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA). The USOA is an accounting system prescribed by FERC and adopted by this Commission to identify the regulated utility industry's cost, revenues and expenses relating to the provision of utility services.

Q. Mr. Rooney identifies at page 5, line 4 that the Missouri Code of State Regulations “requires that the FERC USOA be followed except as modified.” Does the Commission require the regulated utilities under its jurisdiction use the USOA?

A. Yes. The Commission rules require that the companies books and records utilize the FERC USOA to segregate all of its costs, revenues and expenses relating to the provision of utility service. 4 CSR 240-20.030 Uniform System of Accounts—Electrical Corporations under section 1 states:

> Beginning January 1, 1994, every electrical corporation subject to the commission’s jurisdiction shall keep all accounts in conformity with the Uniform System of Accounts Prescribed for Public Utilities and Licensees subject to the provisions of the Federal Power Act, as prescribed by the Federal Energy Regulatory Commission (FERC) and published at 18 CFR Part 101 (1992) and 1 FERC Stat. & Regs. Paragraph 15,001 and following (1992), except as otherwise provided in this rule. This uniform system of accounts provides instruction for recording financial information about electric utilities. It contains definitions, general instructions, electric plant instructions, operating expenses instructions, and accounts that comprise the balance sheet, electric plant, income, operating revenues, and operation and maintenance expenses.

Q. Does the Commission require that the USOA be used for ratemaking purposes?

A. No. While companies under the jurisdiction of the Commission are required to use USOA for financial and recordkeeping purposes, the Commission has recognized there are exceptions to using USOA for the ratemaking process. In the Commission’s rule 4 CSR 240-20.030(4), states:

> In prescribing this system of accounts, the commission does not commit itself to the approval or acceptance of any item set out in any account for the purpose of fixing rates or in determining other matters before the commission. This rule shall not be construed as waiving any recordkeeping requirement in effect prior to 1994.

This section of the Commission's rules indicates that the Commission is not bound by the USOA to establish rates.

Q. At page 7, line 13 of Mr. Rooney's rebuttal testimony he identifies how he believes cost of removal and salvage were treated in several rate cases the Company filed with the Commission. Did Mr. Rooney list all the recent rate cases the Company filed with the Commission?

A. No. Mr. Rooney left out the most recent, and perhaps the most important rate case relating to this issue. The Company filed a general rate case on June 8, 2001 that was designed as Case No. ER-2001-672. While that case resulted in a Stipulation and Agreement of the whole case, the treatment of depreciation rates was specifically identified.

Q. How is Aquila currently treating cost of removal and salvage in its books and records?

A. The Company is currently expensing cost of removal / salvage on its books. The Company was authorized to expense these amounts by the Commission in the last rate case, Case No. ER-2001-672. In response to Data Request No. 276, where cost of removal and salvage amounts were requested for several years, Aquila stated in note to the 2002 year that "for MPS electric and common plant only, beginning with the year 2002 cost of removal and salvage proceeds are charged to expense. This is in accordance with the stipulation and agreement in Missouri Rate Case ER-2001-672."

Q. Since Aquila's last case resulted in a settlement, was there any agreement for ratemaking treatment of cost of removal and salvage?

A. Yes. Specifically, the Company agreed to the expensing of cost of removal / salvage on its books and records. The Stipulation and Agreement in Case No. ER-2001-672, contained a section "Resolutions of Issues, that had a subsection "Depreciation" of the Stipulation and Agreement, the following appears:

> A. The Parties agree that the Commission's order approving this Stipulation and Agreement should order UtiliCorp to implement, and UtiliCorp agrees to implement, for its MPS division, the depreciation rates contained in the document attached to this Stipulation and Agreement as <u>Exhibit B</u>, effective on the same date as the tariff sheets implementing the rate reduction. These agreed-to depreciation rates are the same depreciation rates that the Staff filed in its direct case in these proceedings. These depreciation rates, which apply to UtiliCorp's MPS electric operations, are based on average service lives ("Asks"), and shall only recover the original cost of plant.
>
> B. For matters within the jurisdiction of the Commission, UtiliCorp shall treat net salvage costs for its MPS electric operations, allocated to Missouri, as an expense for ratemaking purposes.
>
> C. UtiliCorp shall book for its MPS electric operations, now and in the future, current levels of net salvage costs as an expense, and not against accrued depreciation reserve. The Parties agree that in the next general rate increase case or complaint case in which MPS's retail electric rates are under review, the Parties shall be free to contest how future net salvage costs should be booked.
>
> D. On or before August 1, 2002, UtiliCorp will file with the Commission its next depreciation study for its MPS electric operations, provided to the Staff its workpapers for that study, and supply the underlying data for that study to the Staff in Gannett Fleming format.

[Source: page 5 of Stipulation and Agreement in Case No. ER-2001-672]

The Company agreed to use Staff's depreciation rates that excluded a component for cost of removal and salvage for financial purposes because it specifically benefited in doing so.

Q. Is there language that is usually included in stipulations and agreements that reserve ratemaking principles?

A. Yes. Typically there is language in Stipulation And Agreements that protects the parties' positions for future rate cases. In Case No. ER-2001-672, in the General

Provisions section of the Stipulation and Agreement under subsection, "Reservations" the following appears:

> A. The terms of this Stipulation and Agreement have resulted from extensive negotiations among the Parties and are interdependent. By entering into this Stipulation and Agreement, none of the Parties shall be deemed to have approved or acquiesced in any ratemaking or procedural principle, or any method of cost determination or cost allocation, and none of the Parties shall be prejudiced or bound in any manner by the terms of this Stipulation and Agreement in this or any other proceeding, **except as expressly specified herein.** Unless, the Commission approves of this Stipulation and Agreement in its entirety, without condition or modification, this Stipulation and Agreement shall be null and void, and none of the Parties shall be bound by any of the terms hereof.
>
> B. The Parties agree that this Stipulation and Agreement and any and all discussion related hereto shall be privileged and shall not be subject to discovery, admissible in evidence, or in any way used, described or discussed in any proceeding, except as expressly specified herein.

[Source: page 8 of the February 5, 2002, Unanimous Stipulation and Agreement; emphasis added]

This is typical language for settlements, in that there is no ratemaking precedent relating to the issues unless they are specifically noted. In Case No. ER-2001-672, the Company agreed to use Staff's depreciation rates that excluded the cost of removal and salvage component from the rate and agreed not to use the accrual method. This was so noted in the Stipulation and Agreement.

Q. Did Aquila agree to the terms of the Stipulation and Agreement?

A. Yes. The Company signed the agreement along with the other Parties and it was filed on February 5, 2002 with the Commission. The Commission approved the Stipulation and Agreement on February 21, 2002. In the Ordered section of the Report and Order under item 2, the Commission stated "that UtiliCorp United, Inc., is ordered to comply with the terms of the Unanimous Stipulation and Agreement."

Q. What benefit did the Company receive in agreeing to use the Staff's depreciation rates in the last case?

A. By using Staff's depreciation rates, which excluded the cost of removal and salvage component, the Company was able to use lower depreciation rates, thereby resulting in a reduced level of depreciation expense. This had the effect of showing an increase to the Company's earnings, which was a direct benefit to Aquila. It was the desire of Aquila management to show an increase in earnings.

While the amount in the last case was settled as a global settlement with identification of the dollar value for specific issues, the depreciation rates excluding cost of removal and salvage, were specifically identified.

Q. How does using Staff's depreciation rates improve the Company's earnings?

A. Because the depreciation rates developed in the last case did not include a component for cost of removal and salvage, the depreciation rates were lower which resulted in a smaller depreciation expense that the Company charged to its earnings. The Company's net income was greater using Staff's depreciation rates than they would have been if they would have used the previous prescribed rates that included the cost of removal and salvage components.

Q. Was the Company in violation of the Federal Code of Regulations and the Commission's rules by using Staff's depreciation rates in the last case?

A. Staff does not believe so. However, if the Company stands by Mr. Rooney's assertions that he has made in his rebuttal testimony whereby he alludes that not including cost of removal and salvage as part of the depreciation rates is in violation of the Commission's rules, then the Company must believe that it violated the rules in the last case when it agreed to use depreciation rates that excluded cost of removal and salvage and not recording the amounts in the accumulated depreciation reserve.

Q. Did Aquila violate the Commission's rule on cost of removal and the Code of Federal Regulations relating to the USOA in the Company's last case?

A. From Staff's perspective, no. However, the Company appears to be supporting such a notion in Mr. Rooney's rebuttal testimony. At page 5 he states the following with regard to the treatment of cost of removal and salvage:

- the Missouri Code of State Regulations requires the FERC USOA be followed
- the Missouri Code of State Regulations provides that upon retirement "each electrical corporation subject to the commission's jurisdiction shall…charge original cost less net salvage to account 108
- account 108 is accumulated depreciation – a component rate base
- both FERC and the Missouri Code of State Regulations direct that net salvage be recorded in accumulated depreciation account 108

Mr. Rooney seems to be inferring that since the Company expensed cost of removal / salvage during the last two years, it has violated the Commission's rules relating to the use of the accumulated depreciation reserve. Staff witness Schad addresses this point in her surrebuttal testimony.

Staff believes Aquila has complied with the Commission's Order with regard to Case No. ER-2001-672 and the Commission's rules. As noted earlier, the Commission is not bound by the reporting requirements of FERC USOA for ratemaking purposes. The use of actual expenditures for cost of removal / salvage instead of the estimates that is part of the accrual process is not a violation the Code of Federal Regulations or the Commission rules.

Q. Has Aquila always followed the USOA guidelines?

A. No. When the Company filed its 1990 general rate case, Case No. ER-90-101, it proposed, and the Commission ultimately approved, a method to recover construction type costs for the Sibley generating facility's life extension program. The Company also requested this same deferral treatment for that generating unit's western coal conversion project in Case No. ER-93-37. The Company requested two Accounting Authority Orders (AAO) to defer costs that would ordinarily be expensed or lost when construction was completed on these two projects under the USOA. While the Commission authorized the use and rate recovery of the Sibley AAOs, the Company benefited directly from the deviation from FERC's USOA.

Q. How did the Company benefit from the AAOs?

A. The USOA is very explicit on how construction expenditures are recorded and when the charges are to stop. Because the Sibley upgrades were significant capital expenditures, the Company timed the effective dates of its two rate cases to match the in-service dates of the construction projects. Since the timing was not exact, there was a gap between when the construction was complete and when rates went into effect. The AAO deferrals captured certain costs during the period from the end of construction to the dates new rates went into effect.

Q. How would the USOA handle this situation?

A. The USOA does not provide for this circumstance. The USOA provides for the accounting treatment of construction expenditures. When construction is completed on a project, the costs that have been identified in FERC Account 107-Construction Work In Progress, are transferred to Account 101-Plant In Service. While the capital expenditures are included in CWIP, the utility is permitted to calculate an "allowance for funds used during construction" (AFDC) that is a deferred return or carrying charge for the invested construction expenditures. The AFDC amount is included in the final cost of the construction and is transferred to plant in service at the time of completion.

When the CWIP balance is transferred to plant in service, depreciation starts in the month of transfer so that depreciation expense is charged to earnings through the income statement.

Q. How were these costs treated in the AAO?

A. The Company was permitted to capture the AFDC and depreciation expense as deferred costs that were ultimately included in rates for recovery. In addition to these two cost items, the Company was also permitted to include in its deferral amount property taxes associated with the plant investment for the period of time between the completion of the plant and when rates went into effect. Staff has referred to this process as continuation of construction accounting.

Q. How did the Company recover the deferred costs?

A. The AAOs were included in rates to be recovered over a 20-year period of time with the unamortized balance to be included in rate base.

Q. Has Staff included the Sibley Life Extension Program and Western Coal Conversion AAOs in this case?

A. Yes. Staff witness Trisha Miller addresses the rate treatment for the AAOs relating to the Sibley construction projects. She further discusses the accounting treatment known as "construction accounting."

Q. Is the construction accounting consistent with the USOA?

A. No. The Commission afforded the Company special rate treatment because of the circumstances surrounding the two Sibley construction projects. The Commission permitted the deferral of these costs and the rate treatment associated with them through its state Commission ratemaking process. While the USOA has accounts that are used to identify the deferral process the USOA does not provide for the continuation of construction accounting as it was approved by the Commission for the Sibley rebuild projects.

Q. Did the Company benefit from the Commission's treatment of the two Sibley AAOs?

A. Yes. Under normal accounting practice as prescribed by the USOA, the Company would not be permitted to defer the costs and receive ratemaking treatment for costs during the period of time from when the construction was finished and the rate recovery started. Typically, the timing between rate recovery and the completion of construction projects are part of the regulatory lag process. On major construction projects such as power plants, the utility will time its rate case so that there is the shortest time between when the plant addition is completed and rate recovery starts. Aquila benefited directly from the Commission's ability to deviate from the USOA.

Q. Are the amounts the Company is proposing for cost and removal and salvage actual "known" amounts?

A. No. While Staff bases its cost of removal and salvage on actual incurred amounts, Aquila's method is nothing more than estimate. The of cost of removal and salvage amounts do not have to be "estimated" when actual costs are available.

Q. Mr. Rooney has identified in his rebuttal testimony that the use of the five-year average results in an under-recovery of actual expenditures for cost of removal. Please comment.

A. It is noteworthy that Mr. Rooney's analysis using several different scenarios, some of which are not at all realistic, results in a variety of purported unrecovered cost of removal amounts. Mr. Rooney identifies at pages 12 and 13 of his rebuttal testimony that the range of the "unrecovered" amounts for cost of removal is between \$3.8 million and \$5 million over 15 years. While it is not the Staff's intent to propose amounts that result in the unrecovery of reasonable and prudent expenditures of the Company, the \$3.8 million under recovery amount for cost of removal as alleged by Mr. Rooney is significantly different when compared to the approximately \$13 million annual amount of over-collection by the Company for cost of removal. This over-collection for cost of removal is identified in Staff witness Rosella L. Schad's direct testimony (page 14, line 9) where she indicated that the annual amount of cost of removal generated would be over \$14.5 million net of the actual cost of removal of \$1.5 million based on a 5-year average.

Q. Has the Company discussed with Staff the amount that results from the use of the five-year average?

A. No. The Company has not inquired or suggested any amount different from the five-year average that's included in the Staff's case other than the amount that Company witness White is sponsoring in his depreciation testimony. Dr. White is supporting a \$7 million amount for cost of removal. As can be seen from Mr. Rooney's rebuttal schedule HDR-1, the Company has not incurred an actual amount for cost of removal any where near the \$7 million level estimated by Dr. White for any year identified on this schedule since

1982. While the Company criticizes the Staff's level of cost of removal, it makes no attempt to reconcile the amount of cost of removal that has actually been incurred with that which has been estimated by the Company that is substantially greater than the actual amounts.

Q. Has Mr. Rooney's rebuttal analysis identified the problem with the Company's method of over charging its customers?

A. Yes. Mr. Rooney identifies in his rebuttal Schedules HDR-1 and HDR-2, the amounts that he claims is the Company's cost of removal as shown in the FERC Form 1 reports filed annually for the period 1982 to 2001. For any given year provided in this analysis, the amounts of cost of removal and salvage do not come close to the levels that the Company has been over charging its customers. The highest the cost of removal / salvage amount was for this 20-year period was in 1990, when the Sibley life extension program took place. That amount in 1990 was $2.8 million compared with the level that Staff witness Schad calculates that the Company has received in rates for cost of removal / salvage. The recent level of cost of removal / salvage she identifies is an amount of $13 million (page 14, line 13 of Schad rebuttal). The smallest amount in the 20-year period identified by Mr. Rooney is in 1983 when the Company incurred $233,000 of cost of removal / salvage—far from the $7 million being recommend by Aquila in this case.

Aquila is proposing a method of recovering cost of removal / salvage that is sure to result in an over collection from its customers going forward just as it has in the past. If Mr. Rooney's rebuttal analysis demonstrates anything, it is that the over collection of the estimated cost of removal / salvage amounts, when compared to actual amounts that have been paid in the past, will not "fix" itself going forward. If left to the Company's approach, the present day customers will continued to be burden with the over accrual of a cost that is collected but not paid. The actual amounts shown in the column "Net Salvage" on rebuttal Schedules HDR-1 and HDR-2 clearly shows what the problem has been with the "over accrual method." This method provides a substantial "windfall" to the Company.

Q. Mr. Rooney states at page 16, line 18 of his rebuttal testimony that the Company has concerns of not only that "the pay as you go amount proposed by Staff does not cover [Aquila's] pay as you go amounts" but also that "current are being granted lower rates at the expense of future customers (an intergenerational inequity)…" Does Staff similar concerns as expressed by the Company relating to the cost of removal issue?

A. Yes, but from a different perspective. It is commendable of the Company to be concerned about costs charged its future customers. The cost of removal and salvage issue relates more to the past and current customers who have had to pay far in excess amounts for these cost components than what the Company has had to actually pay. The cost of removal and salvage issue relates to customers only paying an on-going level of expenses for cost of removal / salvage and not having to pay in rates excessive amounts over and above those the Company actually incurs.

Q. Does Staff have an outstanding data request to the Company on this issue?

A. Yes. Staff requested supporting work papers from the Company relating to its rebuttal testimony. It is a standard expectation that work papers be provided at the time of filing. I notified the Company on several occasions through e-mail and telephone regarding the need for the work papers supporting the Mr. Rooney's rebuttal analysis identified as Schedules HDR-1 and HDR-2. Mr. Rooney used 20 years of FERC Form 1's for the period 1982 to 2001 as basis for his analysis. While it was not necessary because of an agreement reached with the Parties at the start of the case that work papers supporting testimony filings would be provided, I finally had to submit Data Request No. 707, issued on February 4, 2004. To date this information has not been provided by the Company.

Q. Why did Staff need the support for Mr. Rooney's analysis?

A. Staff has not been able to identify and verify the amounts shown on rebuttal Schedules HDR-1 and HDR-2 for the "Net Salvage" column. The amounts shown on Mr. Rooney's two rebuttal schedules do not reconcile with amounts the Company provided to Staff for cost of removal and salvage in response to Data Request No. 276.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

Non-Proprietary

Support for the EWG Build

Data Request No. 607

Missouri Public Service Commission

Respond Data Request

Data Request No.	0607
Company Name	Aquila, Inc.-Investor(Electric)
Case/Tracking No.	ER-2004-0034
Date Requested	12/02/2003
Issue	Expense - Operations - Purchase Power
Requested From	Denny Williams
Requested By	Cary Featherstone
Brief Description	Support for the EWG Build Option
Description	With respect to the meeting with Bob Holzwarth and Frank DeBacker on October 28, 2003, 1. please supply all analyses relating to the need for Missouri Public Service capacity used to support recommendation presented to Mr. Bob Green during summer of 1998 to "build" generating capacity as an exempt wholesale generator (EWG) non-regulated unit. 2. Provide any notes taken at this meeting by all of those present. 3. Provide letters, e-mail, correspondence and any other communication generated as result of the presentation made by the regulated entity UtiliCorp Power Supply for the EWG proposal.
Response	See attached Word doc from Frank DeBacker for response. Hard copy of detail sent to staff.
Objections	NA

The attached information provided to **Missouri Public Service Commission** Staff in response to the above data information request is accurate and complete, and contains no material misrepresentations or omissions, based upon present facts of which the undersigned has knowledge, information or belief. The undersigned agrees to immediately inform the **Missouri Public Service Commission** if, during the pendency of Case No. **ER-2004-0034** before the Commission, any matters are discovered which would materially affect the accuracy or completeness of the attached information. If these data are voluminous, please (1) identify the relevant documents and their location (2) make arrangements with requestor to have documents available for inspection in the **Aquila, Inc.-Investor(Electric)** office, or other location mutually agreeable. Where identification of a document is requested, briefly describe the document (e.g. book, letter, memorandum, report) and state the following information as applicable for the particular document: name, title number, author, date of publication and publisher, addresses, date written, and the name and address of the person(s) having possession of the document. As used in this data request the term "document(s)" includes publication of any format, workpapers, letters, memoranda, notes, reports, analyses, computer analyses, test results, studies or data, recordings, transcriptions and printed, typed or written materials of every kind in your possession, custody or control or within your knowledge. The pronoun "you" or "your" refers to **Aquila, Inc.-Investor(Electric)** and its employees, contractors, agents or others employed by or acting in its behalf.

Security :	Public
Rationale :	NA

With Proprietary and Highly Confidential Data Requests a Protective Order must be on file.

Schedule 1-2

AQUILA, INC.
CASE NO. ER-2004-0034
MISSOURI PUBLIC SERVICE COMMISSION
DATA REQUEST NO. MPSC-607

DATE OF REQUEST: December 2, 2003

DATE RECEIVED: December 2, 2003

DATE DUE: December 22, 2003

REQUESTOR: Cary Featherstone

BRIEF DESCRIPTION: Support for the EWG Build Option

QUESTION:

With respect to the meeting with Bob Holzwarth and Frank DeBacker on October 28, 2003, 1. please supply all analyses relating to the need for Missouri Public Service capacity used to support recommendation presented to Mr. Bob Green during summer of 1998 to "build" generating capacity as an exempt wholesale generator (EWG) non-regulated unit. 2. Provide any notes taken at this meeting by all of those present. 3. Provide letters, e-mail, correspondence and any other communication generated as result of the presentation made by the regulated entity UtiliCorp Power Supply for the EWG proposal.

RESPONSE:

1. Analyses relating to the need for additional power supply resources for Missouri Public Service was communicated to Staff and OPC through the following:
   Attachment 1 – Letter of April 7, 1998 to Mike Proctor, Staff, with a copy to Ryan Kind, OPC.
   Attachment 2 – 1998-2003 Preliminary Energy Supply Plan presented to Staff and OPC on August 24, 1998
2. Any notes taken at the referenced meeting are no longer available.
3. Any letters, e-mail, correspondence, and other communication are no longer available.

ATTACHMENT:
Attachment 1 – Letter of April 7, 1998 to Mike Proctor, Staff, with a copy to Ryan Kind, OPC.
Attachment 2 – 1998-2003 Preliminary Energy Supply Plan presented to Staff and OPC on August 24, 1998

ANSWERED BY: Frank DeBacker

Frank W DeBacker
SIGNATURE OF RESPONDENT

ER-2004-0034
MPSC-607
Attachment #1

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
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.

ER-2004-0034
MPSC-607
Attachment #2

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

1.4 Conclusions

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

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

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:

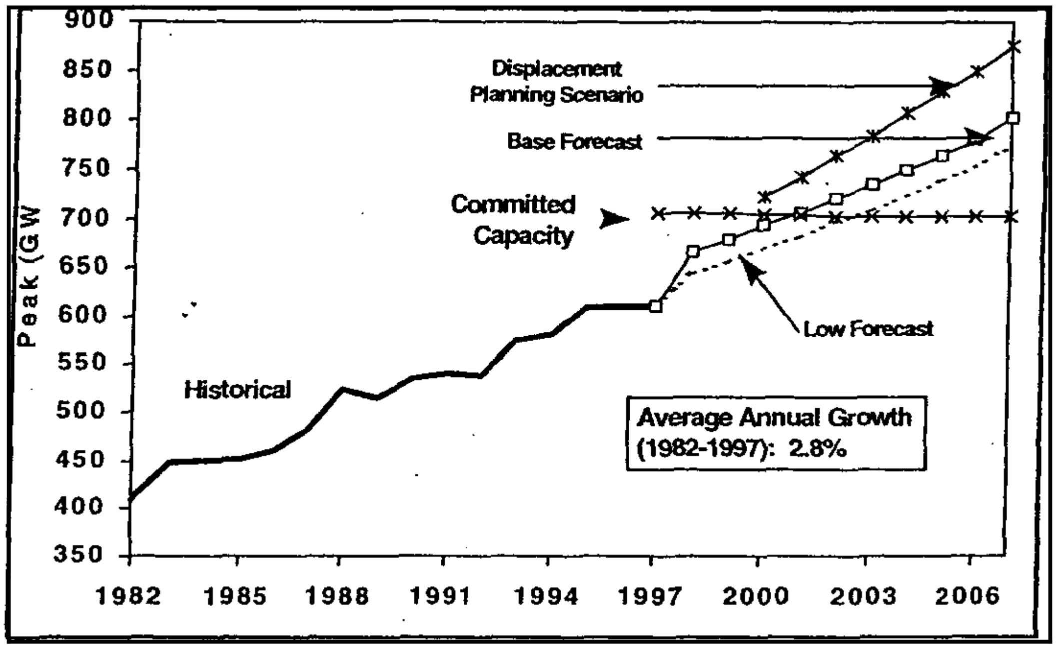
- Negotiate extension of the existing lease agreements on the Greenwood combustion turbines.
- Secure short term capacity to meet MPS' capacity needs thru 2000.
- Pursue the construction of a 500 MW combined cycle unit proposed with an in service date of June 1, 2001.

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

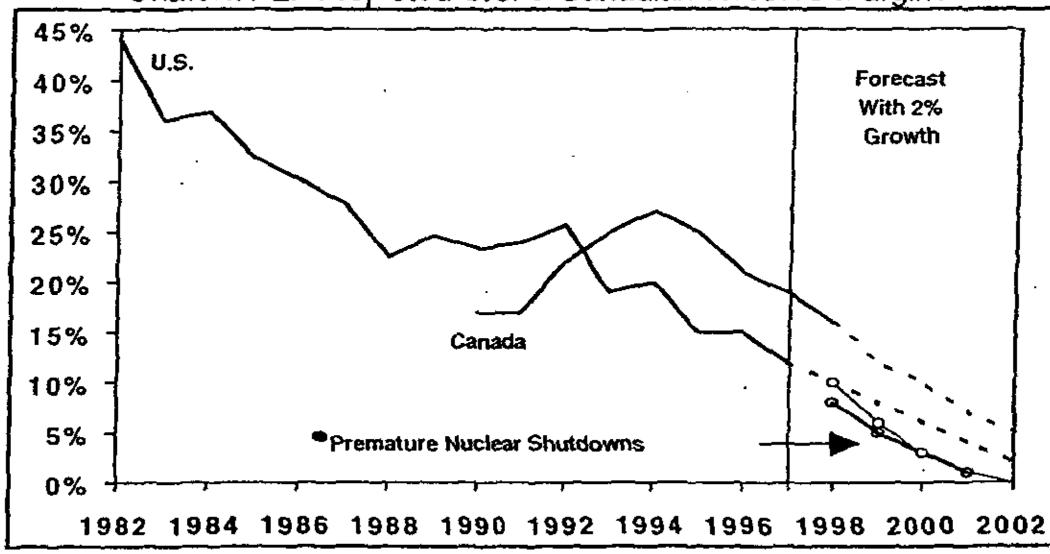


Table 2.1-3: Projected U.S. Regional Reserve Margins

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

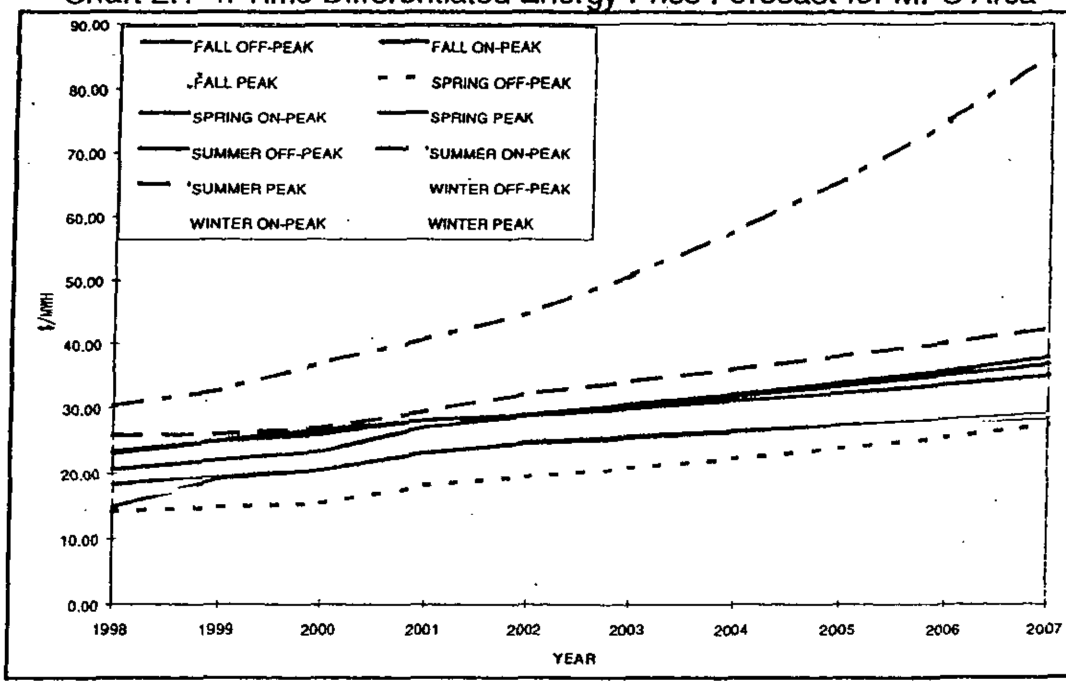
*With Premature Nuclear Shutdowns (NS)
**Region also includes inefficient Fossil capacity with potential for displacement.

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.

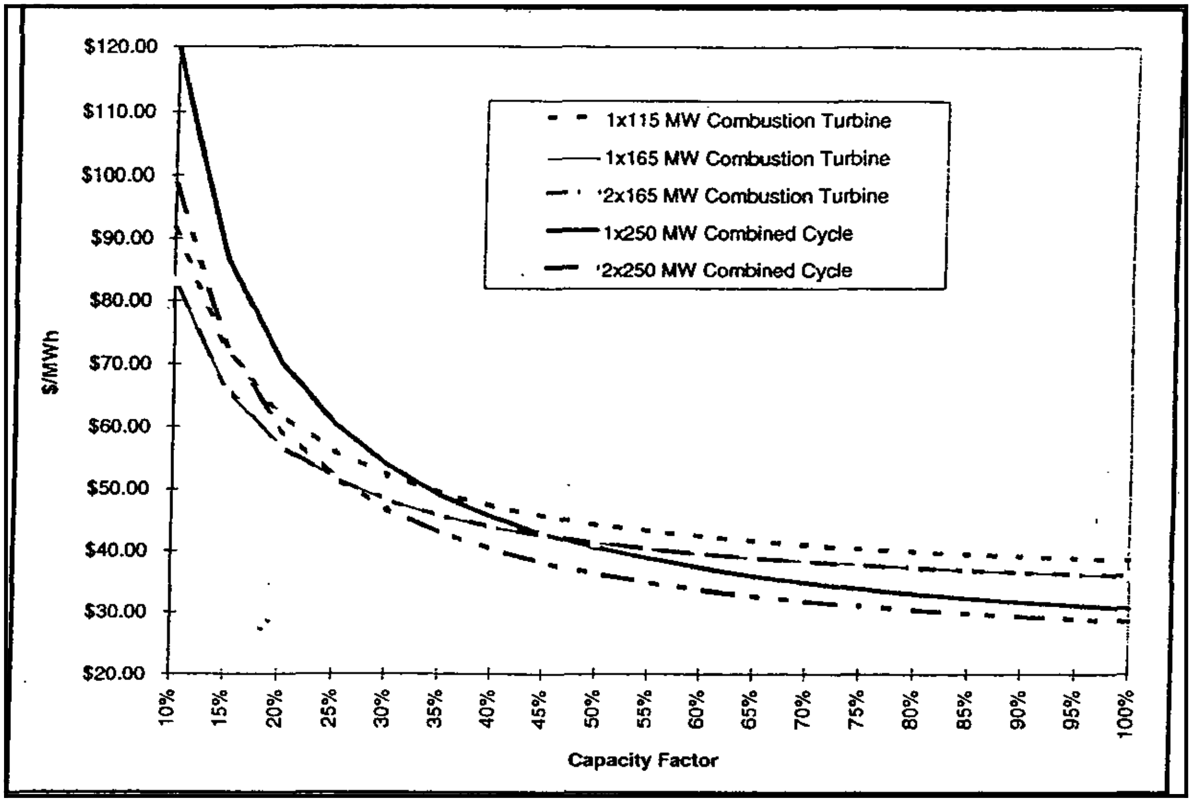
4.4 Resource Analysis

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.

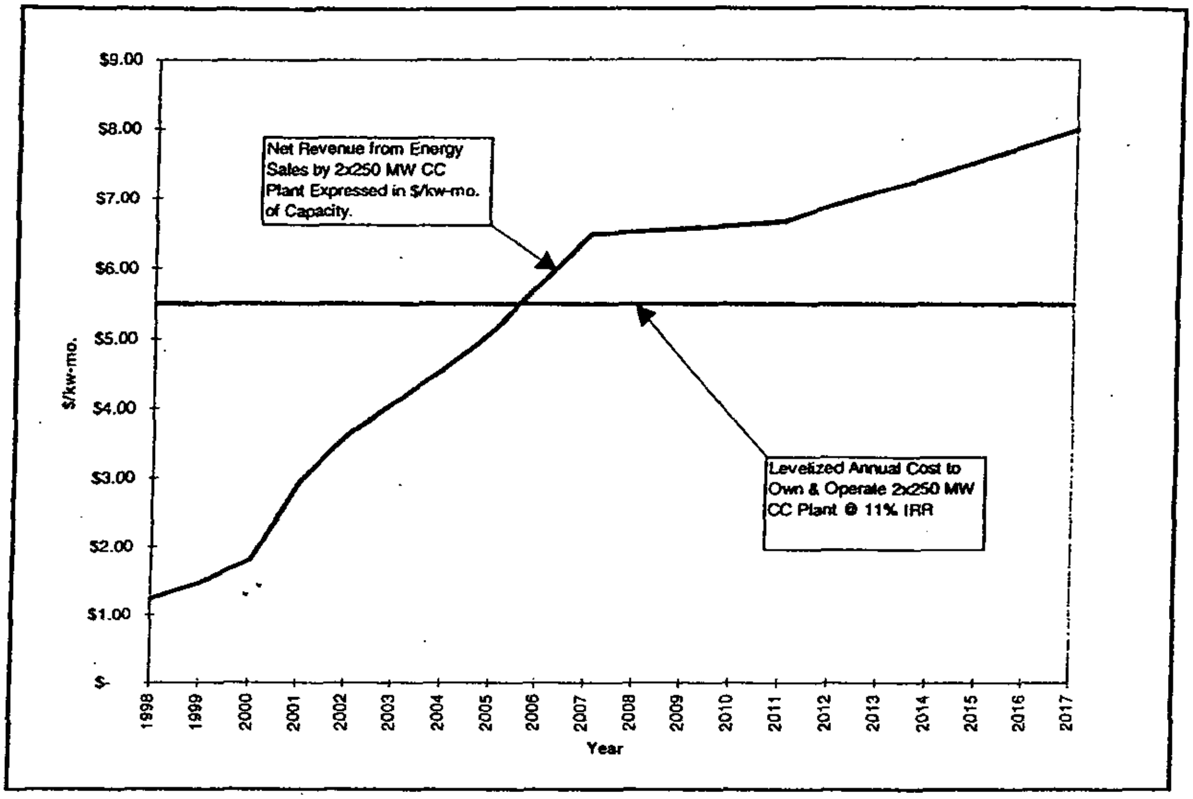
Chart 4.4-1: "All In" Production Cost vs. Load Factor
for five Supply Alternatives



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 (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 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 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 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 3

RealTime Modeling Results with Sales

June 1, 2000 to May 31, 2004

Case	Contract	Capacity MW	Energy MWh	Cost $	Total Purchases $	Total Sales $	Total Generations Cost $	Total Expense $	% Above Least Expensive Case	$ Above Least Expensive Case
Case 1					$ 389,912,026	-$244,101,124	$ 270,450,846	$ 416,261,748	6.4%	$ 25,094,747
	LS Power Unit 1 (Online 2001)	270	5,503,419	$ 172,351,627						
	LS Power Unit 2 (Online 2001)	270	5,215,847	$ 166,023,918						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Parital Requirement)	75	348,547	$ 16,082,792						
	(Peaking Capacity)	25	10,849	$ 1,720,933						
	Unit-Contingent Purchase	55	12,628	$ 3,126,081						
	Sales		-9,638,472	-$244,101,124						
Case 2					$ 56,009,906	-$229,989,146	$ 565,146,241	$ 391,167,001	0.0%	$ -
	Utilicorp Unit 1 (Online 2001)	250	5,263,141	$ 146,501,561						
	Utilicorp Unit 2 (Online 2001)	250	4,741,587	$ 138,812,149						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	103	$ 4,809,452						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,199						
	SPS Option A (Parital Requirement)	75	348,173	$ 16,074,017						
	(Peaking Capacity)	25	11,105	$ 1,728,457						
	Unit-Contingent Purchase	55	12,228	$ 3,110,369						
	Sales		-8,294,721	-$229,989,146						
Case 3					$ 254,759,280	-$115,277,263	$ 292,881,747	$ 436,363,764	11.6%	$ 45,196,763
	CP&L	150	272,064	$ 35,093,650						
	Southern	100	2,040,278	$ 59,698,798						
	Aquila Option 3	100	128	$ 24,370,535						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	122	$ 4,811,451						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Parital Requirement)	75/100	2,732,666	$ 97,754,915						
	(Peaking Capacity)	25	11,069	$ 1,730,085						
	Unit-Contingent Purchase	55	12,622	$ 3,123,522						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,607,503	-$115,277,263						
Case 4					$ 252,834,409	-$115,370,390	$ 292,799,355	$ 430,263,374	10.0%	$ 39,096,373
	CP&L	150	271,678	$ 35,079,240						
	Southern	100	2,035,607	$ 59,600,978						
	NP Energy	100	7,611	$ 18,626,909						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	164	$ 4,816,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Parital Requirement)	75/100	2,735,959	$ 97,822,664						
	(Peaking Capacity)	25	10,904	$ 1,726,163						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,609,397	-$115,370,390						
Case 4a					$ 207,034,425	-$76,232,910	$ 305,746,570	$ 436,548,085	11.6%	$ 45,381,084
	CP&L	150	296,929	$ 35,871,171						
	Southern	100	2,099,871	$ 60,968,896						
	NP Energy	100	19,268	$ 19,001,909						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	Aquila 3	100	131	$ 24,370,845						
	SPS Option A (Parital Requirement)	75	347,940	$ 16,050,715						
	(Peaking Capacity)	25	10,823	$ 1,721,288						
	Unit-Contingent Purchase	55	12,706	$ 3,128,333						
	Peaking Contract		0	$ 1,440,000						
	Sales		-3,081,867	-$76,232,910						
Case 4b					$ 245,656,954	-$104,544,438	$ 299,063,984	$ 440,176,500	12.5%	$ 49,009,499
	CP&L	150	269,141	$ 35,000,521						
	Southern	100	2,095,140	$ 60,891,338						
	NP Energy	100	6,746	$ 18,593,373						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	NorAm	100	1,524,514	$ 72,332,404						
	SPS Option A (Parital Requirement)	75	348,547	$ 16,082,792						
	(Peaking Capacity)	25	10,849	$ 1,720,933						
	Unit-Contingent Purchase	55	12,628	$ 3,126,081						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,071,935	-$104,544,438						
Case 5					$ 227,595,089	-$79,905,446	$ 302,832,926	$ 450,522,569	15.2%	$ 59,355,568
	CP&L	150	294,307	$ 35,788,707						
	Aquila Option 3	100	109	$ 24,368,588						
	NP Energy	100	18,118	$ 18,964,500						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	168	$ 4,816,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Parital Requirement)	75/100	2,736,056	$ 97,824,847						
	(Peaking Capacity)	25	10,904	$ 1,726,163						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 1,440,000						
	Sales		-3,267,595	-$79,905,446						
Case 6					$ 249,212,528	-$107,803,417	$ 292,866,910	$ 434,276,021	11.0%	$ 43,109,020
	Aquila Option 3	100	168	$ 24,374,724						
	NP Energy	100	13,800	$ 16,873,562						
	Southern	100	2,035,607	$ 59,600,952						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	166	$ 4,816,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Parital Requirement)	75/100	2,735,959	$ 97,822,664						
	(Peaking Capacity)	25	10,904	$ 1,726,163						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 6,000,000						
	Sales		-4,401,647	-$107,803,417						
Case 7					$ 297,070,015	-$140,445,134	$ 287,938,305	$ 444,563,186	13.7%	$ 53,396,185
	Southern	100	2,038,417	$ 59,658,506						
	Aquila Option 3	100	196	$ 24,377,567						
	NorAm	100	1,475,468	$ 71,142,954						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Parital Requirement)	75/100	2,736,170	$ 97,325,464						
	(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

AQUILA, INC.
CASE NO. ER-2004-0034
MISSOURI PUBLIC SERVICE COMMISSION
DATA REQUEST NO. MPSC-607
SUPPLEMENTAL RESPONSE

DATE OF REQUEST: December 2, 2003

DATE RECEIVED: December 2, 2003

DATE DUE: December 22, 2003

REQUESTOR: Cary Featherstone

BRIEF DESCRIPTION: Support for the EWG Build Option

QUESTION:

With respect to the meeting with Bob Holzwarth and Frank DeBacker on October 28, 2003, 1. please supply all analyses relating to the need for Missouri Public Service capacity used to support recommendation presented to Mr. Bob Green during summer of 1998 to "build" generating capacity as an exempt wholesale generator (EWG) non-regulated unit. 2. Provide any notes taken at this meeting by all of those present. 3. Provide letters, e-mail, correspondence and any other communication generated as result of the presentation made by the regulated entity UtiliCorp Power Supply for the EWG proposal.

RESPONSE:

1. Analyses relating to the need for additional power supply resources for Missouri Public Service was communicated to Staff and OPC through the following:
   Attachment 1 – Letter of April 7, 1998 to Mike Proctor, Staff, With a copy to Ryan Kind, OPC.
   Attachment 2 – 1998-2003 Preliminary Energy Supply Plan presented to Staff and OPC on August 24, 1998
2. Any notes taken at the referenced meeting are no longer available.
3. Any letters, e-mail, correspondence, and other communication are no longer available.

ATTACHMENT:
Attachment 1 – Letter of April 7, 1998 to Mike Proctor, Staff, With a copy to Ryan Kind, OPC.
Attachment 2 – 1998-2003 Preliminary Energy Supply Plan presented to Staff and OPC on August 24, 1998

ANSWERED BY: Frank DeBacker

____
SIGNATURE OF RESPONDENT

Supplemental Response: See attached "Report on the Evaluation of Power Supply Proposals" dated 8/28/98. Missing page 2 was found and included in this complete copy of the report. Also included is the 2/1/99 update on "Report on the Evaluation of Power Supply Proposals".

Supplemental Attachments: Hard copy of "Report on the Evaluation of Power Supply Proposals" dated 8/21/98 and update to "Report on the Evaluation of Power Supply Proposals" dated 2/1/99.

Supplemental Response ANSWERED BY: Frank DeBacker

RECEIVED
DEC 3 0 2003
UTILITY SERVICES DIV.
PUBLIC SERVICE COMMISSION

Burns & McDonnell 100 1898 • 1998

February 1, 1999

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

Report on the Evaluation of Power Supply Proposals

Mr. DeBacker:

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

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

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

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

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

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

Sincerely,

James M. Flucke

James M. Flucke, P.E.
Project Manager

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

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

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

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

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

Houston Industries
Annual Ownership and Operating Cost
$x1,000

Annual Fixed Cost

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

Total Annual Supply Cost

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

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
GP&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	$ 270,450,846	$ 416,261,748	6.4%	$ 25,094,747
	LS Power Unit 1 (Online 2001)	270	5,503,419	$ 172,351,627						
	LS Power Unit 2 (Online 2001)	270	5,215,847	$ 166,023,918						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (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	$ 1,648,199						
	SPS Option A (Partial Requirement)	75	348,173	$ 16,074,017						
	(Peaking Capacity)	25	11,105	$ 1,728,457						
	Unit-Contingent Purchase	55	12,228	$ 3,110,389						
	Sales		-9,294,721	-$229,989,146						
Case 3					$ 258,759,280	-$115,277,263	$ 292,881,747	$ 436,363,764	11.6%	$ 45,196,763
	CP&L	150	272,064	$ 35,093,850						
	Southern	100	2,040,278	$ 59,698,798						
	Aquila Option 3	100	128	$ 24,370,535						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	122	$ 4,811,451						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,732,666	$ 97,758,915						
	(Peaking Capacity)	25	11,069	$ 1,730,065						
	Unit-Contingent Purchase	55	12,622	$ 3,123,522						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,607,503	-$115,277,263						
Case 4					$ 252,834,409	-$115,370,390	$ 292,799,355	$ 430,263,374	10.0%	$ 39,096,373
	CP&L	150	271,670	$ 35,079,240						
	Southern	100	2,035,607	$ 59,600,970						
	NP Energy	100	7,611	$ 18,626,909						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	168	$ 4,816,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,735,959	$ 97,822,664						
	(Peaking Capacity)	25	10,904	$ 1,726,163						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,609,397	-$115,370,390						
Case 4a					$ 207,034,425	-$76,232,010	$ 305,746,570	$ 436,548,985	11.6%	$ 45,381,984
	CP&L	150	296,929	$ 35,871,171						
	Southern	100	2,099,871	$ 60,988,898						
	NP Energy	100	19,258	$ 19,001,909						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	Aquila 3	100	131	$ 24,370,845						
	SPS Option A (Partial Requirement)	75	347,040	$ 16,050,715						
	(Peaking Capacity)	25	10,823	$ 1,721,288						
	Unit-Contingent Purchase	55	12,706	$ 3,128,333						
	Peaking Contract		0	$ 1,440,000						
	Sales		-3,081,867	-$76,232,010						
Case 4b					$ 245,656,954	-$104,544,438	$ 299,063,984	$ 440,176,500	12.5%	$ 49,009,499
	CP&L	150	269,141	$ 35,000,521						
	Southern	100	2,095,140	$ 60,891,338						
	NP Energy	100	6,746	$ 18,593,373						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	NorAm	100	1,524,514	$ 72,332,404						
	SPS Option A (Partial Requirement)	75	348,547	$ 16,082,792						
	(Peaking Capacity)	25	10,849	$ 1,720,933						
	Unit-Contingent Purchase	55	12,628	$ 3,126,081						
	Peaking Contract		0	$ 1,440,000						
	Sales		-4,071,935	-$104,544,438						
Case 5					$ 227,595,089	-$79,905,446	$ 302,832,926	$ 450,522,569	15.2%	$ 59,355,568
	CP&L	150	294,307	$ 35,788,707						
	Aquila Option 3	100	109	$ 24,364,566						
	NP Energy	100	18,118	$ 18,964,500						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	168	$ 4,816,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,736,056	$ 97,824,847						
	(Peaking Capacity)	25	10,904	$ 1,726,163						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 1,440,000						
	Sales		-3,267,595	-$79,905,446						
Case 6					$ 249,212,528	-$107,803,417	$ 292,866,910	$ 434,276,021	11.0%	$ 43,109,020
	Aquila Option 3	100	168	$ 24,374,724						
	NP Energy	100	13,800	$ 18,873,562						
	Southern	100	2,035,607	$ 59,600,952						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	168	$ 4,816,156						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (Partial Requirement)	75/100	2,735,959	$ 97,822,664						
	(Peaking Capacity)	25	10,904	$ 1,726,163						
	Unit-Contingent Purchase	55	12,606	$ 3,123,748						
	Peaking Contract		0	$ 6,000,000						
	Sales		-4,401,647	-$107,803,417						
Case 7					$ 297,070,015	-$140,445,134	$ 287,938,305	$ 444,563,186	13.7%	$ 53,396,185
	Southern	100	2,038,417	$ 59,658,506						
	Aquila Option 3	100	196	$ 24,377,567						
	NorAm	100	1,475,468	$ 71,142,954						
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529						
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200						
	SPS Option A (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					$ 247,482,085	$ 228,719,801	$ 476,201,886	4.9%	$ 22,182,486
	LS Power Unit 1 (Online 2001)	270	3,450,651	$ 128,875,814					
	LS Power Unit 2 (Online 2001)	270	1,159,977	$ 79,414,823					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (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	$ 3,019,083					
	Peaking Contract		0	$ 1,440,000					
Case 4					$ 190,167,020	$ 264,956,444	$ 455,123,464	0.2%	$ 1,104,064
	CP&L	150	67,346	$ 28,689,735					
	Southern	100	935,112	$ 36,457,450					
	NP Energy	100	8,090	$ 18,644,079					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (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	$ 30,595,167					
	Southern	100	1,272,189	$ 43,749,960					
	NP Energy	100	19,468	$ 19,007,529					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	Aquila 3	100	131	$ 24,370,845					
	SPS Option A (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	647,710	$ 51,208,572					
	SPS Option A (Partial Requirement)	75	175,698	$ 12,420,153					
	(Peaking Capacity)	25	10,918	$ 1,723,930					
	Unit-Contingent Purchase	55	9,776	$ 3,016,014					
	Peaking Contract		0	$ 1,440,000					
Case 5					$ 191,200,852	$ 278,177,382	$ 469,378,234	3.4%	$ 15,358,834
	CP&L	150	125,345	$ 30,504,582					
	Aquila Option 3	100	131	$ 24,370,845					
	NP Energy	100	18,990	$ 18,991,617					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (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	$ 24,377,567					
	NP Energy	100	14,527	$ 18,899,618					
	Southern	100	935,112	$ 36,457,442					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (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	$ 24,377,567					
	NorAm	100	390,664	$ 44,985,611					
	Aquila Option 1a 6/1/2000 - 9/30/2000	100	26	$ 4,801,529					
	Aquila Option 1b 10/1/2000 - 5/31/2001	75	0	$ 1,648,200					
	SPS Option A (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

SCHEDULES 2 THROUGH 8

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DEEMED

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Non-Proprietary

Greenwood Power Plant

Analysis

Greenwood Power Plant
units one and two
Comparasion of purchase versus lease costs to ratepayers

#	Dates	Lease Payments	Depreciation Rate	Annual Depreciation	Accumulated Depreciation	Net Plant Book Value @ 12/31	Rate of Return	Rate Base Portion of Revenue Requirement	Revenue Requirment (Rate Base plus Depreciation)	Revenue Requirement Plus Depreciation Minus Lease Payments
	original cost $11,482,874									
	Plant values at inception		0.03636	$ -	-	$ 11,482,874.00				
1	June 1, 1975 - December 31, 1975	$ 553,130	0.03636	$ 243,552	$ 243,552	$ 11,239,322	10.5450%	$ 691,359	$ 934,911	$ 381,780.52
2	January 1, 1976 - December 31, 1976	$ 1,106,260	0.03636	$ 417,517	$ 661,069	$ 10,821,805	10.5450%	$ 1,141,159	$ 1,558,677	$ 452,416.51
3	January 1, 1977 - December 31, 1977	$ 1,106,260	0.03636	$ 417,517	$ 1,078,586	$ 10,404,288	10.5450%	$ 1,097,132	$ 1,514,649	$ 408,389.31
4	January 1, 1978 - December 31, 1978	$ 1,106,260	0.03636	$ 417,517	$ 1,496,104	$ 9,986,770	12.2578%	$ 1,224,158	$ 1,641,676	$ 535,415.51
5	January 1, 1979- December 31, 1979	$ 1,106,260	0.03636	$ 417,517	$ 1,913,621	$ 9,569,253	12.4622%	$ 1,192,539	$ 1,610,057	$ 503,796.63
6	January 1, 1980 - December 31, 1980	$ 1,106,260	0.03636	$ 417,517	$ 2,331,138	$ 9,151,736	12.7066%	$ 1,162,874	$ 1,580,392	$ 474,131.63
7	January 1, 1981 - December 31, 1981	$ 1,106,260	0.03636	$ 417,517	$ 2,748,656	$ 8,734,218	12.7066%	$ 1,109,822	$ 1,527,340	$ 421,079.38
8	January 1, 1982 - December 31, 1982	$ 1,106,260	0.03636	$ 417,517	$ 3,166,173	$ 8,316,701	14.5124%	$ 1,206,953	$ 1,624,470	$ 518,210.12
9	January 1, 1983 - December 31, 1983	$ 1,106,260	0.03636	$ 417,517	$ 3,583,690	$ 7,899,184	15.2414%	$ 1,203,946	$ 1,621,464	$ 515,203.39
10	January 1, 1984 - December 31, 1984	$ 1,106,260	0.03636	$ 417,517	$ 4,001,207	$ 7,481,667	15.2414%	$ 1,140,311	$ 1,557,828	$ 451,567.90
11	January 1, 1985 - December 31, 1985	$ 1,106,260	0.03636	$ 417,517	$ 4,418,725	$ 7,064,149	15.2414%	$ 1,076,675	$ 1,494,193	$ 387,932.42
12	January 1, 1986 - December 31, 1986	$ 1,106,260	0.03636	$ 417,517	$ 4,836,242	$ 6,646,632	15.2414%	$ 1,013,040	$ 1,430,557	$ 324,296.94
13	January 1, 1987 - December 31, 1987	$ 1,106,260	0.03636	$ 417,517	$ 5,253,759	$ 6,229,115	15.2414%	$ 949,404	$ 1,366,922	$ 260,661.46
14	January 1, 1988 - December 31, 1988	$ 1,106,260	0.03636	$ 417,517	$ 5,671,277	$ 5,811,597	15.2414%	$ 885,769	$ 1,303,286	$ 197,025.98
15	January 1, 1989 - December 31, 1989	$ 1,106,260	0.03636	$ 417,517	$ 6,088,794	$ 5,394,080	15.2414%	$ 822,133	$ 1,239,651	$ 133,390.50
16	January 1, 1990 - December 31, 1990	$ 1,106,260	0.03636	$ 417,517	$ 6,506,311	$ 4,976,563	14.8936%	$ 741,189	$ 1,158,707	$ 52,446.53
17	January 1, 1991 - December 31, 1991	$ 1,106,260	0.03636	$ 417,517	$ 6,923,829	$ 4,559,045	14.8936%	$ 679,006	$ 1,096,523	$ (9,736.83)
18	January 1, 1992 - December 31, 1992	$ 1,106,260	0.03636	$ 417,517	$ 7,341,346	$ 4,141,528	14.8936%	$ 616,823	$ 1,034,340	$ (71,920.18)
19	January 1, 1993 - December 31, 1993	$ 1,106,260	0.03636	$ 417,517	$ 7,758,863	$ 3,724,011	14.8936%	$ 554,639	$ 972,157	$ (134,103.54)
20	January 1, 1994 - December 31, 1994	$ 1,106,260	0.03636	$ 417,517	$ 8,176,380	$ 3,306,494	14.8936%	$ 492,456	$ 909,973	$ (196,286.90)
21	January 1, 1995 - December 31, 1995	$ 1,106,260	0.03636	$ 417,517	$ 8,593,898	$ 2,888,976	14.8936%	$ 430,273	$ 847,790	$ (258,470.25)
22	January 1, 1996 - December 31, 1996	$ 1,106,260	0.03636	$ 417,517	$ 9,011,415	$ 2,471,459	14.8936%	$ 368,089	$ 785,607	$ (320,653.61)
23	January 1, 1997 - December 31, 1997	$ 1,106,260	0.03636	$ 417,517	$ 9,428,932	$ 2,053,942	14.8936%	$ 305,906	$ 723,423	$ (382,836.97)
24	January 1, 1998 - December 31, 1998	$ 1,106,260	0.03636	$ 417,517	$ 9,846,450	$ 1,636,424	12.0446%	$ 197,101	$ 614,618	$ (491,642.05)
25	January 1, 1999 - December 31, 1999	$ 1,106,260	0.03636	$ 417,517	$ 10,263,967	$ 1,218,907	12.0446%	$ 146,812	$ 564,330	$ (541,930.34)
26	January 1, 2000 - May 31, 2000	$ 460,942	0.03636	$ 173,966	$ 10,437,933	$ 1,044,942	12.0446%	$ 52,441	$ 226,407	$ (234,534.92)
		$ 27,564,315		$ 10,437,933				$ 20,502,011	$ 30,939,944	$ 3,375,629.14
	Second lease first five years									
27	June 1, 2000 - December 31, 2000	$ 1,824,640	0.03636	$ 243,552	$ 10,681,484	$ 801,390	12.0446%	$ 56,306	$ 299,858	$ (1,524,782.44)
28	January 1, 2001 - December 31, 2001	$ 3,051,641	0.03636	$ 417,517	$ 11,099,002	$ 383,872	12.0446%	$ 46,236	$ 463,753	$ (2,587,888.19)
29	January 1, 2002 - December 31, 2002	$ 2,920,819	0.03636	$ 417,517	$ 11,516,519	$ (33,645)	12.0446%	$ (4,052)	$ 413,465	$ (2,507,354.68)
30	January 1, 2003 - December 31, 2003	$ 2,789,997	0.03636	$ 417,517	$ 11,934,036	$ (451,162)	12.0446%	$ (54,341)	$ 363,176	$ (2,426,820.88)
31	January 1, 2004 - December 31, 2004	$ 2,659,175	0.03636	$ 417,517	$ 12,351,553	$ (868,679)	12.0446%	$ (104,629)	$ 312,888	$ (2,346,287.09)
32	January 1, 2005 - May 31, 2005	$ 1,085,278	0.03636	$ 417,517	$ 12,769,070	$ (1,286,196)	12.0446%	$ (154,917)	$ 262,600	$ (822,677.63)
		$ 14,331,551		$ 2,331,137				$ (215,397)	$ 2,115,740	$ (12,215,810.91)
	Second lease second five years									
33	June 1, 2005 - December 31, 2005	$ 1,443,076		$ 417,517	$ 13,186,587	$ (1,703,713)	12.0446%	$ (205,205)	$ 212,312	$ (1,230,764.02)
34	January 1, 2006 - December 31, 2006	$ 2,419,335		$ 417,517	$ 13,604,104	$ (2,121,230)	12.0446%	$ (255,494)	$ 162,023	$ (2,257,311.41)
35	January 1, 2007 - December 31, 2007	$ 2,266,709		$ 417,517	$ 14,021,621	$ (2,538,747)	12.0446%	$ (305,782)	$ 111,735	$ (2,154,973.94)
36	January 1, 2008 - December 31, 2008	$ 2,135,887		$ 417,517	$ 14,439,138	$ (2,956,264)	12.0446%	$ (356,070)	$ 61,447	$ (2,074,440.14)
37	January 1, 2009 - December 31, 2009	$ 2,005,065		$ 417,517	$ 14,856,655	$ (3,373,781)	12.0446%	$ (406,358)	$ 11,159	$ (1,993,906.33)
38	January 1, 2010- May 31, 2010	$ 812,732		$ 417,517	$ 15,274,172	$ (3,791,298)	12.0446%	$ (456,647)	$ (39,130)	$ (851,861.20)
		$ 11,082,803		$ 2,505,102				$ (1,985,556)	$ 519,546	$ (10,563,257.04)
	Second lease third five years									
39	June 1, 2010 - December 31, 2010	$ 758,222		$ 417,517	$ 15,691,689	$ (4,208,815)	12.0446%	$ (506,935)	$ (89,418)	$ (847,640.26)
40	January 1, 2011 - December 31, 2011	$ 1,743,421		$ 417,517	$ 16,109,206	$ (4,626,332)	12.0446%	$ (557,223)	$ (139,706)	$ (1,883,126.99)
41	January 1, 2012 - December 31, 2012	$ 1,612,599		$ 417,517	$ 16,526,723	$ (5,043,849)	12.0446%	$ (607,511)	$ (189,994)	$ (1,802,593.19)
42	January 1, 2013 - December 31, 2013	$ 1,481,777		$ 417,517	$ 16,944,240	$ (5,461,366)	12.0446%	$ (657,800)	$ (240,283)	$ (1,722,059.39)
43	January 1, 2014 - December 31, 2014	$ 1,350,955		$ 417,517	$ 17,361,757	$ (5,878,883)	12.0446%	$ (708,088)	$ (290,571)	$ (1,641,525.59)
44	January 1, 2015 - May 31, 2015	$ 540,186		$ 417,517	$ 17,779,274	$ (6,296,400)	12.0446%	$ (758,376)	$ (340,859)	$ (881,044.77)
	Totals	$ 7,487,159		$ 2,505,102				$ (3,795,933)	$ (1,290,831)	$ (8,777,990)
				$ -	$ -			$ -	$ -	-
	Grand Lease Total	$ 60,465,828		$ 17,779,274	$ 17,779,274			$ 14,505,125	$ 32,284,399	$ (28,181,429.00)
	Grand Rate-Base Total	$ 32,284,399								
	Difference	$ 28,181,429								

Schedule 9-2