Exhibit No.: 60
Issues: Aries
Witness: Max A. Sherman
Sponsoring Party: Aquila Networks-MPS
[redacted]
Case No.: ER-2004-0034 &
[redacted]

Before the Public Service Commission
of the State of Missouri

Rebuttal Testimony

of

Max A. Sherman

Denotes Highly Confidential Information

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REBUTTAL TESTIMONY OF
MAX A. SHERMAN
AQUILA, INC. D/B/A AQUILA NETWORKS-MPS
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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI
REBUTTAL TESTIMONY OF MAX A. SHERMAN
ON BEHALF OF AQUILA, INC.
D/B/A AQUILA NETWORKS-MPS [redacted]
CASE NOS. ER-2004-0034 [redacted]

Q. Please state your name and business address.

A. Max A. Sherman, 10418 West 125th Terrace, Overland Park, KS 66213.

Q. What is the purpose of your testimony?

A. I have been retained by Aquila, Inc. ("Aquila" or "Company") to review and respond to the Commission Staff's ("Staff") direct testimony as filed in Case No. ER-2004-0034, as that testimony relates to the charges being paid by Aquila Networks – Missouri Public Service ("MPS" or "Missouri Public Service") to MEP Pleasant Hill, LLC for capacity and energy supplied to MPS by the Aries Plant in Pleasant Hill, Missouri.

Q. Is this testimony based on your work with MPS?

A. No. As my resume attached as Schedule MS-1 shows, my positions with Aquila were always on the non-regulated merchant side of the Company. My testimony is based upon my personal involvement in Aquila's merchant business.

Q. Please describe your educational background.

A. I graduated with a Bachelor of Science degree in Engineering from the University of California at Los Angeles ("UCLA") in 1971. I subsequently graduated in 1974 from UCLA with a Master of Science degree in Engineering, with a specialization in metallurgy and metal processing. I also earned a Master of Science degree in Nuclear Engineering in 1975 from the University of Wisconsin (Madison).

Q. Please describe your work experience.

A. I have over twenty-five years of experience in development, design, construction, operation, asset management, regulation, and origination and power marketing with regard to generating assets in the electric power industry. The assets in question have been nuclear, coal, gas/oil steam boilers, combined cycle, and peaking combustion turbine generation. This experience was obtained while I was employed by both utilities and utility affiliates, with the vast majority involving generating assets located in the Southwest Power Pool ("SPP") and Southeastern Electric Reliability Council ("SERC") regions. My resume is attached as Schedule MS-1.

Q. Before proceeding, please define each of the abbreviations used in your testimony.

A. The abbreviations and the entities they represent are as follows:

Company	Aquila, Inc., formerly UtiliCorp United Inc.
MPS	Aquila, Inc.'s regulated electric operations formerly known as Missouri Public Service, a division of the Company.
MEPPH	MEP Pleasant Hill, LLC, the entity formed by Aquila Merchant to own and operate its power plant at Pleasant Hill, Missouri. It is now co-owned by subsidiaries of Aquila and Calpine Corporation.
Aquila Merchant	Aquila Merchant Services, Inc., a wholly owned subsidiary of the Company. Aquila Merchant operations include Aquila Power Corp., Aquila Energy Marketing Corp., Merchant Energy Partners and MEPPH.
FERC	Federal Energy Regulatory Commission
MoPSC	Missouri Public Service Commission (also referred to as "Commission")
PSA	Power Supply Agreement between MEPPH and MPS, dated February 22, 1999
Staff	Staff of the Missouri Public Service Commission

Q. Have you previously filed testimony before the Commission?

A. No.

Q. Have you participated in rate or other regulatory proceedings before other commissions?

A. Yes. As a power marketer and a business development manager for firms affiliated with Entergy, I was responsible for preparing FERC filings to obtain approval for certain capacity and associated energy sales to other utilities. While at the Company, I submitted testimony in a FERC proceeding where Aquila filed a complaint alleging that another utility had failed to comply with its Open Access Transmission Tariff ("OATT") obligations under FERC Order 888.

Q. Have you testified before state legislative bodies?

A. Yes. I have testified before the Kansas House Utilities Committee, Kansas Senate Utilities Committee, and a Missouri House/Senate Joint Interim Committee on Telecommunications and Energy.

Q. How have you organized your rebuttal testimony?

A. I will be rebutting the testimony of Staff witnesses Mr. Mark L. Oligschlaeger and Mr. Cary G. Featherstone as their direct testimony addressed the issue of the PSA and their proposed disallowance of a portion of the capacity charges related to that contract. I have organized my rebuttal testimony as follows:

1. Executive Summary
2. I explain why Staff is wrong in its belief that MPS entered into the PSA with MEPPH in order to enhance Company profits at its customers' expense.
    a. I explain my work in responding to the MPS request for proposal ("RFP") that led to the PSA.

b. I explain that the RFP process and subsequent negotiations recognized that any power supply agreement would be subject to close regulatory scrutiny.

c. I explain why the PSA is a fair and balanced contract from Aquila Merchant's perspective.

d. I review the decision, from Aquila Merchant's perspective, to enter into the transaction with Missouri Public Service;

3. I explain the major cost elements that Staff overlooked or ignored in its proposed disallowance of capacity costs under the Power Supply Agreement;

4. I show why no disallowance of costs is appropriate when all major cost elements of the plant are considered.

1. EXECUTIVE SUMMARY

Q. What is the executive summary of your Rebuttal Testimony?

A. The conclusions of my testimony are as follows:

1. Based on my direct involvement in the bidding process, the process was fair and complied with the FERC code of conduct on affiliate transactions. No favoritism was shown to Aquila Merchant by MPS.

2. The PSA is fair and balanced.

3. Based on what Aquila Merchant knew at the time, the decision to enter into the transaction with MPS made sense. The bid price to MPS was low but judged adequate to initiate the project, and it was expected that sales to others would provide the remaining revenues needed to support the plant economics. The plant cost was reasonable then and now, and replication costs would in all likelihood be higher today.

4. Staff's analysis considers only the cost associated with a permanent financing that did not occur. Staff did not consider operation and maintenance costs, PILOT ("payments in lieu of taxes") payments to Cass County, actual interest expense, depreciation and amortization, or a return on the equity that has been invested by the partners in the plant. When those costs that were overlooked or not considered by Staff are recognized, MPS capacity payments are far less than what would result from a pro rata allocation of actual fixed costs. Failure to recognize those costs in Staff's analysis invalidates Staff's conclusions.
5. When Staff's methodology is corrected by incorporating substantial and material fixed costs that were not considered, the resulting cost allocation exceeds what MPS is paying in capacity charges under the PSA. As a result, the capacity charge is fully justified and no disallowance of such costs in MPS rates is reasonable or appropriate.

2. STAFF IS INCORRECT THAT FAVORITISM AND "A GOAL OF MAXIMIZING PROFITS" WERE THE BASIS FOR THE PSA

a. MEP Participation in the RFP Process

Q. What is the purpose of this part of your testimony?

A. My purpose is to rebut statements by Mr. Oligschlaeger in his Direct Testimony alleging that favoritism was shown in the award to Aquila Merchant.

Q. What did Mr. Oligschlaeger state?

A. He alleged that affiliate abuse had occurred and that it was the intent of Company senior management to increase profits at the expense of the utility and its native load customers.

See Oligschlaeger Direct Testimony at p. 3, lines 1-4; pp. 10-11; pp. 14-16. He concluded that favoritism was shown in making the award to Aquila Merchant.

Q. How will you rebut the Staff witness' conclusions?

A. I will explain Aquila Merchant's participation in the MPS RFP process that led to the PSA with MEPPH. This testimony is based on my personal knowledge of these events. I will explain why the PSA is a fair and balanced contract from Aquila Merchant's perspective. I will also review the decision, from Aquila Merchant's perspective, to enter into the transaction with MPS.

Q. Did Aquila Merchant participate in this RFP process?

A. Yes. Aquila Merchant responded to the RFP issued on May 22, 1998.

Q. Which Aquila Merchant entities participated?

A. The initial participant was Aquila Power Corp., a power marketing subsidiary of Aquila Merchant. Later, Merchant Energy Partners participated.

Q. What did Aquila Power Corp. offer?

A. In July 1998, Aquila Power offered capacity from a combined cycle unit to be constructed and owned by LS Power in Batesville, Mississippi. The proposal is provided in Schedule MS-2.

Q. Please describe the project.

A. A combined cycle power plant typically consists of the following: (a) one or more combustion turbine-generators fueled by natural gas; (b) heat recovery steam generators ("HRSGs") that use the exhaust energy from the combustion turbines to make steam; and (c) one or more steam turbine-generators that use the steam from the HRSGs to make additional electricity.

The Batesville Plant, developed by LS Power, consists of three "1x1" combined cycle "trains." Each "train" consists of a combustion turbine-generator, a heat recovery steam generator, and a steam turbine-generator set. The project is located at an industrial park in Batesville, Mississippi, and is directly interconnected with Entergy Mississippi, Inc. and the Tennessee Valley Authority. The project includes a pipeline lateral that interconnects with multiple interstate natural gas pipelines.

Q. Why was Aquila Power able to offer capacity and energy from this project?

A. Aquila Power had negotiated and entered into a "tolling agreement" with the developer in May 1998 for rights to all the capacity and associated energy from one of the "trains" at the Batesville Plant. The "train" that was ultimately assigned to the contract was designated Unit 3, and will be referred to henceforth as Batesville Unit 3.

Q. What is a tolling agreement?

A. It is a common industry term used to describe the charge or "toll" paid to use an energy facility, similar to the toll a driver pays to cross a bridge or drive on a turnpike. A tolling agreement is similar to a unit power sales agreement where the purchaser gains the right to take capacity and associated energy from a specified power plant. However, in a tolling agreement the purchaser is responsible for the fuel supply. A good analogy is to a car lease. The lessee doesn't own the car, but under the lease pays a monthly fee for the right to use the car and independently pays for the gasoline (fuel). If the lessor is responsible for the car's maintenance, such leases typically charge the lessee a mileage fee to cover that maintenance expense. At the end of the lease, the car is returned to the owner and the lessee's obligations end. The lessee then makes other arrangements for transportation or, in this case, the supply of capacity and energy.

Q. Was Aquila Power's decision to enter into a purchase commitment from Batesville Unit 3 in any way related to the Missouri Public Service RFP?

A. No, however, an understanding of Aquila's interest in the Batesville Unit 3 is relevant to MEPPH's decision to respond to the MPS RFP.

Q. Please explain.

A. In December 1997, the project developer (LS Power) issued a request that asked interested purchasers to submit prices at which they were willing to purchase capacity and energy from the project. Aquila Power responded in late January 1998, and was short listed in February 1998. Contract negotiations were held through May 1998, and the contract was executed on May 21, 1998. The power marketers at Aquila Power did not become aware of the existence of the Missouri Public Service RFP until June 1998.

Q. What role did you play in negotiation of the Batesville Unit 3 tolling agreement?

A. I led the Aquila Merchant negotiation team in its dealings with LS Power.

Q. Why did you have this assignment?

A. At the time, I was a power marketing director for Aquila Power for the south central U.S. region, where the Batesville plant was located.

Q. Why did Aquila Power enter into the tolling agreement with LS Power?

A. Aquila Power had previously decided that it needed to control a certain amount of generation to support its energy trading and marketing business. A "toll" from Batesville Unit 3 was an opportunity to control gas-fired supply with a competitive heat rate compared to the existing gas steam boiler fleet in the region.

Q. Who was responsible for the initial proposal to MPS in response to its May 1998 RFP?

A. I was the responsible individual.

Q. Why were you responsible for the initial proposal?

A. Aquila Merchant believed that Batesville Unit 3 was a logical generating source that would be responsive to the RFP. At the time, I was the power marketer most familiar with what Aquila Power could offer from that unit.

Q. What were the essential elements of the initial proposal from Aquila Power to MPS?

A. The essential elements of the proposal, which is attached as Schedule MS-2, were as follows:

1. Term:	One to four years
2. Type of service:	Unit power with 97% minimum guaranteed equivalent availability.
3. Designated Unit:	Batesville Unit 3
4. Quantity:	Various options of 75 and 100 MW; shown in the proposal.
5. Capacity price:	Priced under various options; shown in the proposal. Pricing for early termination was also included.
6. Energy price:	$100/MWh plus actual cost of transmission losses and/or ancillary services for delivery to MPS.
7. Delivery Points:	MPS' interconnections with the Eastern interconnection.
8. Transmission:	To be billed to MPS at Aquila's actual cost. Several potential transmission paths from the Batesville project to MPS were identified.

Q. Were you aware that there were other bidders?

A. We did not have any information but were confident there were other bidders. Aquila Power's experience was that there were usually a number of bidders in response to RFPs.

Q. Were you aware of the number or identity of other bidders to MPS?

A. No.

Q. What did MPS do with the proposal?

A. It ultimately resulted in a supply agreement with MPS for June through September 2000.

Q. What was your role in concluding those arrangements?

A. I did not participate in concluding those arrangements. The last participation I had in the RFP process on the Batesville proposal was in early November 1998. At that time, I sent a letter to MPS advising that Aquila Power remained interested in providing power supply resources to MPS. That letter is attached as Schedule MS-3.

Q. Why did you not participate in concluding these arrangements?

A. In November 1998, I accepted a position with Aquila's Merchant Energy Partners, a new entity within Aquila Merchant, and transferred to that department effective December 1, 1998. Responsibility for the proposal from Batesville Unit 3 remained with Aquila Power, the Company's power marketing organization.

Q. Did you participate in the Merchant Energy Partners bidding to MPS?

A. Yes, I participated in the process starting mid-December 1998.

Q. What was your responsibility in the bidding process?

A. I was named project manager. My role was to assist in winning an award from MPS and, if successful, to lead the development team to get the project into construction.

Q. Please explain your role in assisting Aquila Merchant's winning the award from MPS.

A. At the time I began participating in the process, MPS had not selected a party with whom to negotiate a power supply agreement for the June 2001 through May 2005 time frame. The bidding process was still under way. MPS was asking Aquila Merchant questions on its previously submitted proposal. I assisted in preparing responses, which are attached as Schedule MS-4. The most important of those responses, in my view, were pricing reductions provided on January 12, 1999. We had been advised by Mr. Frank DeBacker of MPS that Aquila Merchant was not the low bidder. He asked if we could improve our offer. I understand this was standard operating procedure for MPS in dealing with bidders. We responded with the January 12 letter that is a part of Schedule MS-4.

Q. What was the result of the revised pricing letter dated January 12, 1999?

A. MPS notified us by letter dated January 15, 1999 that Aquila Merchant had been selected for negotiations.

Q. Were other bidders offered the opportunity to improve their offers to MPS?

A. I had no knowledge at that time. Table 3 of Mr. DeBacker's Rebuttal Testimony at 26 indicates that he advised the remaining bidder that it was not the low bidder, but that it did not improve its offer.

b. The RFP Process and Subsequent Negotiations Recognized that any Power Supply Agreement would be the subject of close Regulatory Scrutiny

Q. Are you aware of any facts that cause you to believe that the bidding process favored Aquila Merchant?

A. No. My understanding is that MPS, as regulated utility serving native load customers, was obligated to obtain the least cost supply regardless of the source.

Q. Did you see, hear, or experience anything that suggested the process favored an award to MEP over another bidder?

A. Absolutely not. In fact, I would suggest the contrary.

Q. Please explain.

A. Based on my participation during the bidding process, MPS would gladly have awarded the power supply contract to a non-affiliate. I also believe that a "tie" in the bidding would probably have resulted in that outcome.

Q. Why would MPS favor a non-affiliate's proposal over an affiliate's bid?

A. *To avoid the extreme level of regulatory scrutiny that automatically comes with an* affiliate transaction. In such transactions Staff regulators and others usually presume that the regulated entity is "guilty" of favoritism until proven otherwise.

Q. Why do you believe MPS awarded the power supply contract for 2001 to 2004 to MEP?

A. The only possible reason is that it offered the least cost to the native load ratepayer when compared to the other alternatives considered. Otherwise, there was no reason to do so.

Q. Why wouldn't Company senior management require the power supply contract to be awarded by MPS to MEP, as Mr. Oligschlaeger suggests in his Direct Testimony at pages 10-16, even if it were not the low bid?

A. From my perspective as the Aquila Merchant project manager for what became the Aries Power Plant, the reasons are obvious:

1. The PSA would have to be submitted to the Missouri Public Service Commission and the Federal Energy Regulatory Commission. The pricing and terms of the contract would become public information. Had the MEPPH price exceeded the price of the other bidder, or if the terms were unfavorable to MPS, that party would have the opportunity to intervene and attempt to show that it should have been awarded the PSA.
2. Had favoritism been shown to MEPPH, it would have been a violation of the FERC code of conduct under which all the Companies' entities operated. Violation of the FERC code of conduct could be grounds for FERC revoking the authority of the Company's regulated and non-regulated businesses to sell power at market prices, or imposing a fine. Aquila Merchant's business model was focused on wholesale sales

across the country, not to its affiliates. There was simply no reason to put the merchant business at risk due a code of conduct violation involving an affiliate.

3. At the time, Aquila Merchant had filed a complaint against another utility, alleging a violation of its Open Access Transmission Tariff ("OATT") in FERC Docket No. EL98-36-000. As a member of Aquila Merchant, I was involved in the prosecution of that complaint. This proceeding was important to Aquila Merchant's business as it sought open access to the transmission system of a large electric utility. Because that case involved policy issues that might affect every OATT under FERC jurisdiction, the last thing Aquila Merchant needed in that case was the respondent regulated utility defending its conduct by citing affiliate abuse by Aquila's own regulated affiliate.

4. Finally, evidence of favoritism could delay development and construction of *any* winning project that would have to be constructed, be it that of MEPPH or of another party. Aquila Merchant understood that it was absolutely necessary for the winning bidder to meet the in-service date of June 1, 2001 specified by MPS because of the need to replace expiring purchase power contracts. If approval of any project had been delayed due to allegations of or a showing of favoritism, the in-service date could not have been met by MEPPH due to the lead times required to permit, contract for and construct the project.

Q. Why do you believe that another project could not have been built in time?

A. My role was to assist in winning an award from MPS, and, if successful, to get the project into construction. Based on the lead time requirements for contracting, permitting, site acquisition and all the other elements of successful power plant project development, there was not time available for an extended period of regulatory scrutiny that would result from a showing of favoritism in an award to MEPPH, regardless of what party ultimately was awarded a contract.

Q. Are you aware of any evidence suggesting it was less expensive for MPS to purchase power rather than construct its own generation?

A. Based on my experience as a power marketer at Entergy, since the mid-1980's it had been less expensive for a utility to enter into power purchase arrangements than to build and own a new generating unit.

Q. Did you find that the MPS bidding process demonstrated favoritism to Aquila Merchant?

A. No.

Q. What were the internal criteria Aquila Merchant had to meet in submitting a bid to MPS?

A. The same as for any other developer. The project had to meet a target "hurdle rate," i.e., an internal rate of return ("IRR") if it won the award. This would be determined in an economic model referred to as a "project pro forma" used to project the costs, revenues and expenses associated with the project.

Q. Has that model been provided to the Commission Staff?

A. Yes. The pro forma used for the initial pricing (before the pricing reduction letter contained in Schedule MS-4) was provided to Staff in response to Data Request No. MPSC-301.

Q. Did the pro forma include revenues from sources other than MPS?

A. Yes. Estimated revenues from sales into the wholesale market were included. The methodology for determining those estimates is discussed in the response to Staff Data Request No. MPSC-371.

Q. What costs were included in the pro forma provided in response to Staff Data Request No. MPSC-301?

A. The pro forma included estimates of direct capital costs to construct the plant, construction and permanent financing costs, non-fuel operating and maintenance expense, and fuel costs for sales to non-affiliates. It also showed an internal rate of return on equity that would be required to be invested in the project to obtain the debt needed to construct, own and operate the project.

Q. Did Aquila Merchant intend (as alleged in Mr. Oligschlaeger's Direct Testimony at pages 12-13 and page 15) for MPS to cover all the fixed costs of the plant?

A. No. As found in the pro forma provided to Staff in response to Data Request No. MPSC-301, revenues from MPS were expected to cover the majority of the fixed costs through May 2005, and then zero thereafter. As will be shown later, the actual share of costs covered by MPS is much lower.

Q. Was this information made available to Aquila senior management?

A. Yes. The presentation to senior management on this project on January 5, 1999 was based on the pro forma referred to above. It included revenues from MPS and expected revenues from future sales into the wholesale market that were expected to cover the cost of the project. In particular, the Aquila Merchant presented projected internal rates of return to senior management that included those revenues. Documents reflecting this information were provided in response to Data Request No. MPSC-301.

Q. Did you attend the presentation to senior management on January 5, 1999?

A. Yes.

Q. Was there any discussion of MPS covering all the fixed costs of the proposed plant?

A. No such statement on MPS covering all the fixed costs of the proposed project was made or suggested by anyone at that meeting.

Q. What prospects did Aquila Merchant face if it had not won the award?

A. At the time, Aquila Merchant's MEP unit was investigating tolling transactions involving other power plants, fuel supply agreements for other projects, and other transactions. The types of transactions MEP was focusing on are listed in a management presentation provided to the Staff in response to Data Request No. MPSC-301. MEP would have gone about its business and explored other opportunities, such as exploring power purchase arrangements with other project developers. There were numerous generating projects proposed at the time by a number of development firms. There was also a project development opportunity in another part of the country that MEP was asked to explore.

Q. What is the conclusion of this part of your testimony?

A. Based upon my direct involvement in the bidding process, the process was fair and complied with the FERC code of conduct on affiliate transactions. No favoritism was shown to the merchant power side of the business from Aquila's regulated affiliate.

c. The MPS/MEPPH Power Sales Agreement: Its Background and Logic

Q. What is the purpose of this part of your testimony?

A. My purpose is to review the PSA's terms and conditions, and explain why it is a fair and balanced contract from MEP's perspective. This is intended to rebut Mr. Oligschlaeger's statements in his Direct Testimony, noted above, that favoritism was shown by the Company in the MPS award of the contract to Aquila Merchant, and that there was affiliate abuse.

Q. Please describe the Power Sales Agreement.

A. The PSA is a *tolling agreement*, with performance guarantees and penalties, which makes it advantageous for the buyer compared to a unit power sales agreement.

Q. Why?

A. A tolling agreement enables the purchaser of the power to manage the largest component of its variable cost – the cost of fuel. A purchasing utility knows its load shape, net area energy requirements, its dispatch stack and the peak demands that determine both the short-term and long-term fuel requirements for a power plant to supply energy to serve native load. Far more than a developer or owner of merchant generation, a regulated utility with the obligation to serve has extensive experience in purchasing fuel to meet native load requirements, and is equipped to manage the purchases of commodity and transport to serve that load. A developer will not have the detailed knowledge of a specific utility's energy requirements that determine optimal fuel purchase decisions.

Q. Why is the cost of fuel so important?

A. Fuel cost is usually the largest component of total production costs for a combined cycle power plant, and can be the largest cost component. Taking the PSA as an example, the capacity charge from 2002 to May 2005 is approximately ***_______________*** for 200 MW of capacity from October through March and 500 MW of capacity from April through September. If the Aries plant were dispatched at an intermediate load factor of approximately 40%, at today's gas cost (using the calendar 2004 Henry Hub index "strip" of $5.42 on 12/29/2003 and assuming the Williams index basis differential roughly offsets gas transport costs), fuel cost would be approximately $5.42/MMBtu x 7.2 MMBtu/MWh x 350 MW x 8760 hours/year x 0.4 = roughly $48 million/year. If the dispatch is at a 25% annual load factor rather than 40%, estimated annual fuel cost for

2004 would be roughly \$48 million x 25%/40% or approximately \$30 million. This sample calculation illustrates that "the money is in fuel cost" for intermediate and base-load plants.

Q. Is a tolling agreement advantageous for the seller?

A. Yes. It transfers risk of fuel management to the utility purchaser, relieving the merchant developer or owner of the plant from those responsibilities. The developer/owner of a plant is less qualified to manage fuel costs than the buyer, as explained above. The merchant operator/owner is left with managing risks and performance of the plant, which are more suited to their responsibilities as asset owners and managers. Those risks and obligations include meeting in-service dates and operating performance guarantees.

Q. Are there circumstances where a tolling agreement may not be as attractive to a purchaser as a unit power sales agreement?

A. Yes.

Q. Please explain.

A. Unit power sales agreements provide for the seller, not the buyer, to provide the fuel. For solid fuel projects with long-term supply arrangements and stable pricing, fuel costs are known with more certainty at the time the purchaser enters into the power purchase arrangement. In addition, solid fuel technical and quality specifications can limit the ability of a purchaser to readily substitute or provide a separate fuel supply. An example would be a power supply purchase from a coal-fired power plant with long-term coal supply and rail transportation arrangements from specific mines. Another would be a power purchase from a nuclear plant, where the cost/MMBtu of fuel in the core is well known in advance. In both examples (particularly the nuclear plant), it isn't practical for the purchaser to provide its own fuel supply. However, for a gas-fired power plant with a homogeneous fuel like pipeline-quality natural gas that can be purchased on the spot market or through short-term or long-term contracts, a tolling agreement makes more sense.

Q. Please describe the principles of risk allocation and mitigation under the PSA for both parties.

A. The basic principles are simple and straightforward. MPS contracted for capacity at a fixed price, selecting quantities of capacity that were higher during the summer period than the winter. MPS largely avoided the risk of escalating costs associated with power project development, design and construction. The small MPS cost changes that occurred are documented in Schedule MS-5. If the availability of the capacity didn't meet defined levels, there would be a pro rata reduction in the capacity payments for the applicable period. MPS also contracted for energy at heat rates that were the lower of actual or guaranteed values. This meant that any heat rate improvements that were added to the final design of the plant would benefit MPS, as well as MEPPH. MPS controlled and provided the fuel supply, paid a variable O&M (operating and maintenance) charge and received a large number of starts per combustion turbine per year without paying a major maintenance "start charge." These provisions allowed MPS to transfer most of the construction, capital cost and operating risks to another party.

Q. What else did MPS receive under the PSA?

A. MPS would receive the power at the interconnection point with its transmission system, avoiding power transmission risk and costs associated with imports across other systems, such as curtailment. MPS also had the right to determine which natural gas pipeline would interconnect with the project. MPS would be committed for a limited term of four years, enabling it to revisit the wholesale power market and avoid a long-term ownership commitment for the life of the asset, which might not be the best economic choice compared to other alternatives. MPS also avoided the risk of owning a "stranded asset." During the procurement process Congress was considering national legislation that would offer retail choice to customers, and many states (including neighboring Arkansas, Illinois and Oklahoma) were seriously considering or had passed retail choice legislation. Therefore, at that time it was uncertain how long Missouri native load customers would remain obligated to purchase power supply from their local utility.

Q. What were the risks and opportunities for MEPPH?

A. MEPPH won a competitive bid which would provide a revenue stream to cover for a limited period of time a portion of the fixed costs of the plant it would construct and own. It had the incentive to minimize plant availability risks (and preserve its revenue stream) from MPS with a limited right to provide substitute power to MPS. Aquila Merchant gained the opportunity to sell a portion of the equity in the project to another party for a premium. Aquila Merchant expected that the remaining project costs, and a suitable return, would be earned from sales to other parties from unsold capacity during the term of the sale to MPS, but primarily through sales to third parties after the MPS sale expired. See Response to Staff Data Request MPSC-301. MEPPH took the risks of being able to build the plant within budget, operate it within pro forma cost estimates, and obtain the benefits if it were able to lower costs or increase revenues beyond estimates at the time. It also took the risk that costs could be higher and that revenues could be lower than projected. The proximity of interstate natural gas pipelines in the area gave MEPPH the opportunity to interconnect with more than one pipeline to ensure competition by the pipelines for the project's business, and to minimize transportation and delivered fuel costs.

Q. What was the model for the PSA?

A. The Batesville Unit 3 tolling agreement between LSP Energy, LP and Aquila Power.

Q. Why was this agreement used as a starting point?

A. First, it was a contract that Aquila Power was familiar with, having negotiated it in the spring of 1998 with a non-affiliate, LSP Energy. Second, it was considered a "state of the art" contract because of its recent vintage. Third, it involved a combined cycle power plant, and many of the concepts were relevant to a MEPPH/MPS arrangement. Fourth, it gave Aquila Merchant confidence in a transactional structure where it could accept a role reversal. In the Batesville Unit 3 tolling agreement, Aquila Merchant (through Aquila Power) was the buyer and in this case Aquila Merchant (through MEPPH) would be the seller.

Q. Was the Batesville tolling agreement used as a starting point in other transactions?

A. Yes. Those transactions included two other Aquila Merchant transactions, and three others that I am aware of involving third parties.

Q. What is your conclusion on the merits of the MEPPH contract with MPS?

A. The MEPPH contract with MPS is fair and balanced.

d. Review of the decision from Aquila Merchant's perspective to enter into the PSA with MPS

Q. What is the purpose of this part of your testimony?

A. My purpose is to review the basis for the decision from Aquila Merchant's perspective to enter into the transaction with MPS. My purpose is also to rebut the incorrect assumptions that Mr. Oligschlaeger made in his Direct Testimony at 12-13 that the PSA permitted MEPPH to recover all of its costs.

Q. How is this part of your testimony organized?

A. I will discuss why it made sense for MEPPH to enter into the PSA. I will also discuss the cost of the plant, and why it is larger than what it would have been as a utility plant.

Q. What was the basis for the MEPPH's decision to enter into the PSA with MPS?

A. Before I joined the project, Aquila Merchant had decided to bid power supply to MPS from an EWG that would be constructed to supply the power.

Q. How was the bid price established?

A. Aquila Merchant prepared a pro forma with estimated project costs and estimated revenues over the life of the project. The revenues included those from MPS should Aquila Merchant win the bid, and projections of revenues from the wholesale market for capacity not sold to MPS. This pro forma was the financial model used as the basis for pricing. The model determined the internal rate of return ("IRR") and net present value of the returns to see if the project would meet Aquila Merchant's financial criteria for doing the project.

Q. Has this information been provided to Staff?

A. Yes, it is contained in a pro forma provided in the response to Data Request No. MPSC-301.

Q. How was the final bid price, contained in MEP's January 12, 1999 letter in Schedule MS-4, established?

A. MEP evaluated potential price reductions in response to word from Mr. DeBacker, after January 5, 1999, to the effect that "MEP was not the low bidder, can MEP improve its offer?" Once MEP decided on final pricing, the January 12 letter was completed and delivered to MPS.

Q. Did Aquila Merchant evaluate other markets for the plant capacity and energy besides MPS?

A. Yes.

Q. Why did Aquila Merchant look at other markets?

A. Wholesale power markets were being deregulated as a result of FERC initiatives. FERC Order 888, issued in 1996, required utility transmission owners that were subject to FERC jurisdiction to file Open Access Transmission Tariffs to provide transmission access on a non-discriminatory basis to wholesale market participants. Aquila Merchant was one such participant. Open access transmission service provided opportunities to sell capacity and energy to purchasers located outside MPS. New buyers and sellers, as well as existing utilities, were entering the wholesale market as FERC granted the authority to sell power at market rates to these entities. Lastly, much of the country was considering "deregulation" of retail electric markets. That meant that buyers of capacity and energy might change over time. Local regulated utilities, which had been the major purchasers of those resources, might be replaced by power marketers, aggregators or another entity. In Missouri, retail deregulation was being discussed in the General Assembly. I myself testified on the property tax implications to a joint legislative committee in late 1999. These actual and anticipated changes meant that local markets could change, and that a plant owner should have access to markets elsewhere to be able to sell capacity and energy from a new power plant.

Q. What other markets did Aquila Merchant consider?

A. At the time Aquila Merchant was bidding to MPS, it had considered the need for capacity in a number of reliability regions, including SPP, SERC, MAPP (Mid-Continent Area Power Pool), MAIN (Mid-America Interconnected Network), and ECAR (East Central Area Reliability Coordinating Council). These reliability regions cover most of the central United States and much of the Eastern Interconnection.

Q. How was this market assessment incorporated into the economics of the Pleasant Hill project?

A. During the bidding process, Aquila Merchant projected the need for capacity in these regions starting in the summer of 2005. It also projected the "spark spread," which is the difference between power price and variable production cost, from 1999 forward. The results of this market assessment were incorporated into the project pro forma as part of the projected revenues that were expected to be earned from sales to third parties in the wholesale market.

Q. Did Aquila Merchant expect to continue capacity and energy sales to MPS when the initial contract expired?

A. No.

Q. What did Aquila Merchant conclude after looking at the market in these areas?

A. The conclusion was that the internal rate of return was only ***____*** for the first ***________***, but that it would be ***____*** over a ***_______*** time horizon. The internal rate of return during the early years was below Aquila Merchant's "hurdle rate" for making the investment. However, over the longer time period, the hurdle rate was met. As a result, it made sense to participate in the bidding to MPS.

Q. Was this information provided to Company senior management?

A. Yes, it is contained in presentations that were provided to Staff in the response to Data Request No. MPSC-301. Those presentations include a January 5, 1999 review with senior management and a February 3, 1999 presentation to the Company's Board of Directors.

Q. What was the final cost of the Aries plant?

A. As shown in Schedule MS-8 and our response to Data Request MPSC-231, ***____________.***

Q. Why is the plant more expensive than the initial estimate?

A. The initial estimate did not include increases in the cost of the fixed price engineering, procurement and construction ("EPC") contract, or the combustion turbines, incorporation of the gas pipeline lateral into the project scope, permitting, easement acquisition associated with the gas pipeline lateral, community benefit expenses, increased financial costs, and project contingency. Some of these increases occurred as the project scope became better defined, as is typical on a large construction project. Other cost increases resulted from increasing the plant generating capability to provide future revenues to offset cost increases that were expected or deliberately incorporated, such as the gas pipeline lateral.

Q. What types of cost increases were incurred as the project went through development and construction?

A. The increases consisted of equipment and scope upgrades, changes to the financial structure, and other associated costs and project contingencies.

Q. Please explain.

A. EPC contract cost increases included: (1) equipment and scope upgrades for the larger steam turbine and increased duct firing to upsize project generating capability; (2) adding the capability for the plant to supply its own auxiliary power when operating; (3) adding steam injection for power augmentation and a kettle boiler to upsize project generating capability; (4) technical field assistance from Siemens Westinghouse to assist in commissioning of the combustion turbines; (5) increased site development (i.e., rock excavation) costs; (6) higher insurance costs ***____***. Other changes outside the EPC contract included adding the natural gas pipeline lateral to the project scope, and a larger spare parts inventory. Financing cost changes included interest expense and fees associated with the construction loan and increase in the amount of funds borrowed. Other costs included higher costs of land and easement acquisition than originally projected, and of project management during development and construction. Costs were assigned to "project contingency" in order to plan for unexpected cost changes that were not known but could reasonably be expected to occur, such as the higher cost of fuel used during project testing and commissioning.

Q. *If it were built today, would this same plant cost more or less than ***_______________***?*

A. It is my belief that it would cost at least that much.

Q. Why?

A. The largest cost of the project, by far, was the EPC contract. Black and Veatch ("B&V"), an international engineering/architecture firm with expertise in power plant construction, was the EPC contractor on this project. B&V has advised me that their price to replicate this plant would be higher than the contract price to build the Aries plant, which included the cost of the combustion turbines. I am aware that shortly after the B&V bid pricing was submitted on Aries, B&V bid a comparable job at a price $30 million higher and won the job. In addition, B&V lost a substantial sum on this project.

Q. Would current combustion turbine resale prices lower the cost of building a plant identical to Aries today?

A. This is highly unlikely. Siemens Westinghouse 501 "F" combustion turbines may be available, unused and in storage with owners that did not install such equipment in a generating plant. Some of this equipment may be discounted but it would be re-sold without the manufacturer's warranty, which is a major drawback for the purchaser. Nevertheless, I have been advised that the replication cost by Black and Veatch under an Aries-type EPC contract would be higher than before, even if combustion turbines were purchased at prices below what MEPPH paid.

Q. From the Aquila Merchant perspective, what is your conclusion on the merits of the decision to enter into the transaction with MPS?

A. Based on what Aquila Merchant knew at the time, the decision made sense. The bid price to MPS was low but judged adequate to initiate the project, and it was expected that sales to others would provide the remaining revenues needed to support the plant economics. The plant cost was reasonable then and now, and replication costs would in all likelihood be higher today.

3. Staff Overlooked or Ignored Major Cost Elements in its Analysis of the PSA which Invalidate its Proposed Capacity Charge Disallowance

Q. What is the purpose of this part of your testimony?

A. I identify and explain the major cost elements that Staff overlooked or ignored in its proposed disallowance of capacity costs under the PSA.

Q. What was one of the purposes of Staff witness Mark Oligschlaeger's Direct Testimony?

A. He stated on page 2 of his Direct Testimony that he "… sponsor[ed] the rationale for the *Staff's adjustment to MPS's test year purchased power expenses to remove the portion of* the Aries unit expenses above the actual cost of capacity supplied to the MPS customers."

Q. What was Mr. Oligschlaeger's conclusion?

A. He concluded that MPS was paying 100% of the costs of the capacity but only contracted for 60% of the capacity. See Oligschlaeger Direct Testimony at 12-13, 15-16. For example, he stated on page 12, lines 13-15 that "…it appears that a regulated utility, MPS, is being required to pay for almost all of the costs of the Aries unit, even though it is not entitled to a proportional amount of the unit's capacity." As I explain below, Staff's assumptions are based upon a fundamental misunderstanding of the PSA and a failure to analyze the data provided to Staff by the Company.

Q. How will you rebut the Staff witness' conclusions?

A. I will explain the cost components associated with owning and operating the Aries plant, which are summarized in Schedule MS-8. The total costs are much larger than the figures Staff has used. The true size of those costs invalidates Staff's conclusions.

Q. Did Mr. Oligschlaeger's testimony discuss how evidence was collected to support its position on the issues?

A. Generally, yes. The testimony referred to interviews of several individuals, including me.

Q. Did Mr. Oligschlaeger's Direct Testimony refer to responses to data requests?

A. The testimony explicitly referred to several data requests from a 2001 rate case (Case No. ER-2001-672). However, there were no references that I saw to responses to data requests in this rate case.

Q. Were data requests submitted by Staff in connection with the Aries plant in this rate case?

A. Yes.

Q. Were responses to those data requests provided by the Company?

A. Yes.

Q. Are those responses treated as highly confidential?

A. Yes.

Q. Where are those responses?

A. All highly confidential responses have been placed in a data room at the Company's offices in Kansas City, Missouri. A list of data request responses placed in the data room is provided as Schedule MS-6. There are over 70 such responses.

Q. Have those highly confidential responses been reviewed by Staff?

A. Yes.

Q. What evidence do you have that those highly confidential responses concerning Aries were reviewed by Staff?

A. The Company has maintained logs of the date and time each member of the Staff spent reviewing the highly confidential responses made available in the data room. The logs, and a table prepared from them, are attached as Schedule MS-7.

Q. Do the logs include review periods before Staff's direct testimony was submitted on December 8, 2003?

A. Yes. The logs include over 76 hours of time spent by Mr. Oligschlaeger and Mr. Featherstone during the period October 28 through December 31, 2003. Over 47 of those hours were spent reviewing responses through November 25, 2003.

Q. Have additional responses been placed in the data room since Staff's direct testimony was submitted?

A. Yes. The responses and dates they were placed in the data room are shown in Schedule MS-6.

Q. What costs did Mr. Oligschlaeger believe were the fixed costs of the Aries plant?

A. He testified that certain lease payments were the fixed costs of the plant. See Oligschlaeger Direct Testimony at 12-13.

Q. Do these payments represent the fixed costs of the Aries plant?

A. No.

Q. Why not?

A. The lease payments cited by Mr. Oligschlaeger are based on financing that was never consummated and does not exist. Even had such lease payments existed, they were intended to provide financing for the debt of the plant, but not the equity investment that was used to build the plant. The lease payments were never intended to cover plant O&M (operating and maintenance) costs, payments to Cass County (the actual owner of the plant) in lieu of property taxes, depreciation and amortization expenses, or return on the equity investment in the plant. These costs are separate and distinct from the lease payments that were to be made to a lender that would provide a portion of the total financing for the project.

Q. Has this information been provided to the Staff?

A. Yes. It was provided in and can easily be developed from several data request responses. It was also explained to Staff on January 13, 2004.

a. Explanation of Debt and Equity Costs

Q. What was the final cost of building the plant?

A. The plant cost, shown in Schedule MS-8, is ***______________.***

Q. What is the debt on the plant?

A. As of September 30, 2003, the debt was ***______________.***

Q. What is the equity invested in the plant?

A. The equity is the difference between plant cost and debt, and is ***_________.***

Q. What is the interest expense for the twelve months ending September 30, 2003?

A. The twelve month interest expense ending September 30, 2003, shown in Schedule MS-12, is ***_________.*** This is the interest expense for the construction loan, which remains in effect.

Q. Should an after-tax return on equity be used in determining the fixed costs of Aries?

A. Yes. The testimony in this rate case has two sets of values proposed for it: (1) 12.25% - by Company witness Don Murry's Direct Testimony at 26; and (2) 9.14% - the midpoint of Staff witness David Murray's Direct Testimony at Schedule 23. Both values are net after income taxes.

Q. What pre-tax cost of equity should be used?

A. The pre-tax cost is determined by dividing the after-tax cost by (1 minus a combined federal and state tax rate). I have used the combined federal and state income tax rate of 38.3886% per page 14 of the Direct Testimony of Company witness Ron Klote. Using the actual equity invested in the project, the cost of equity is ***__________*** using Staff's ROE mid-point and ***___________*** using the Company's ROE proposal. These costs are shown in Schedule MS-8.

Q. Should a return on equity be allowed?

A. Yes. Cost of service clearly includes a return on equity. Equity investors will not invest capital if they know the return on their investment will be zero. I have used the ROE values already introduced by the parties in determining fixed costs of the plant.

Q. Given that the debt and equity levels have changed from what was anticipated, what financing costs should Staff have used estimating the fixed costs of the plant?

A. Staff should have used the costs and amounts of debt and equity that do exist, not lease payments under a financing that never occurred.

Q. What is the cost of debt and equity as of September 30, 2003?

A. Interest expense and cost of equity is ***________________________*** depending on the ROE value used.

b. Explanation of Fixed O&M Expenses

Q. What fixed O&M (operating and maintenance) costs were not included in Staff's analysis?

A. Labor, major maintenance, routine maintenance, materials and supplies, contract services, administrative overhead, O&M agreement fees, and other expenses.

Q. Why are O&M costs considered fixed costs?

A. An owner of a power plant must have the ability to generate and deliver electricity from that plant to a customer when the plant is called upon to do so. To have that capability, the plant must be staffed with an operating and maintenance crew, and the plant must be maintained. The costs incurred to do so are largely fixed. The variable costs are discussed separately, below.

Q. What do labor costs consist of?

A. It includes the cost of labor by the plant operator (now a subsidiary of Calpine Corp.) to operate the plant, including straight time, overtime, payroll taxes, benefits, bonus programs, and employee functions.

Q. What does major maintenance expense consist of?

A. These are the costs of combustion turbine inspections (such as hot gas path and major inspections) and maintenance including associated parts and services under a long term service agreement, maintenance and repair of the Heat Recovery Steam Generators ("HRSGs"), maintenance and repair of balance of plant equipment, replacement catalyst for the Selective Catalytic Reduction ("SCR") emissions control portion of the HRSGs, steam turbine inspections, and major work on the zero discharge water treatment system at the plant.

Q. Do these costs vary from year to year?

A. Yes. In particular, combustion turbine maintenance inspections are typically scheduled based upon the combustion turbine manufacturer's maintenance recommendations.

Q. What does routine maintenance consist of?

A. Work on the boilers, turbines, and balance of plant, including water treatment and zero discharge systems.

Q. What do materials and supplies consist of?

A. Service equipment, plant vehicles, water treatment, shop equipment, warehouse equipment, safety equipment, waste disposal, and consumables.

Q. What do contract services consist of?

A. This category includes lateral gas line management, insulation repairs, landscaping, janitorial services, consultants, audit and assessment, outage technical support, distributed control system (DCS) technical support, fire protection, and environmental services.

Q. What does administrative overhead consist of?

A. Training, travel and partnership meetings, office supplies, shipping and freight, license and permitting fees, telephone and utilities, computer network and software fees, office furnishings and miscellaneous equipment, community relations, property taxes (if applicable), and insurance.

Q. What do other expenses consist of?

A. Contingency expenses, if applicable.

Q. What do the O&M agreement fees consist of?

A. This is the fee, above costs, that the operator receives for operating the plant.

Q. Has this fixed cost information been provided to the Staff?

A. Yes. The fixed O&M cost for the twelve months ending September 30, 2003 was provided in the response to Data Request No. MPSC-231. This response is in the data room discussed above.

Q. Was this information reviewed by Staff?

A. The logs provided in Schedule MS-7 show that the response to Data Request No. MPSC-231 containing this information was reviewed on October 28, 30, and November 12, 2003 by Mr. Featherstone. The logs indicate that Mr. Featherstone checked out this response for just under five hours.

Q. Are these costs included in the lease payments that Staff used?

A. No.

Q. What was the actual fixed O&M expense for the twelve months ending September 30, 2003?

A. The expense was ***______________*** and is shown in Schedule MS-8.

Q. In Mr. Oligschlaeger's deposition on January 8, 2004, was he asked what specific cost information contained in the data requests for the current rate case was used in preparing his testimony?

A. Yes. He stated that he did not directly use the cost information in the data room. See Oligschlaeger Dep. at page 55, line 12.

c. Discussion of Variable O&M Expenses

Q. Is variable O&M expense included in the costs described above?

A. No. It is budgeted and identified separately.

Q. What do variable costs consist of?

A. Water supply expense, water treatment chemicals, zero discharge waste disposal costs, electricity (for station service when the plant is not on line and providing its own power for that purpose), and ammonia (for emissions control). In this case, fuel for dispatch is not included because MPS provides the fuel for its electricity requirements from Aries.

Q. What was the actual variable O&M expense for the twelve months ending September 30, 2003?

A. Variable O&M expense for this period was ***___________*** and is shown on Schedule MS-8.

Q. *Was this information reviewed by Staff?*

A. The response to Data Request No. MPSC-289 containing this information was reviewed on October 28, 29, and 30, 2003 by both Mr. Oligschlaeger and Mr. Featherstone. The logs indicate that Mr. Oligschlaeger reviewed this response for three hours and twelve minutes during that period, and that Mr. Featherstone reviewed this response for four hours and six minutes during that period.

Q. Are these costs included in the lease that does not exist?

A. No.

<u>d. Explanation of Payments in Lieu of Taxes ("PILOT") to Cass County</u>

Q. Is a Payment in Lieu of Taxes ("PILOT") included in the fixed O&M costs discussed above?

A. Yes.

Q. What are the PILOT amounts due to Cass County?

A. For calendar year 2002, the amount is ***_________***. For calendar years 2003 through 2006, the amount is ***_______*** annually.

Q. Has this information been provided to Staff?

A. Yes. This information was provided in response to Data Request No. MPSC-561.

Q. Why would Cass County enter into an agreement that resulted in PILOT payments that were lower than property taxes?

A. First, it was a way to keep dollars in Cass County that might otherwise be re-distributed by the State to other areas. Proposed Senate Bill 300 would have distributed property taxes on merchant power plants to local government entities based on pole-miles of the local utility, which if enacted would have reduced Cass County's revenues from the plant by over ***_____.*** By agreeing to a Chapter 100 bond issue and the associated PILOT, that scenario was avoided. Cass County received the PILOT payments from MEPPH for itself and other government entities in the county. Second, the agreement was an economic development incentive to attract a large project that would provide several hundred construction jobs, and permanent jobs for the operating crew. Third, the project would help expand Cass County's water supply, which was considered deficient. The Aries plant consumes large volumes of water when it is operating, so MEPPH contracted with the City of Kansas City's Water Services Department to supply water to the plant through a new water pipeline to be extended to the plant. That pipeline was sized to exceed Aries requirements, leaving water capacity available for sale by Kansas City to other purchasers (such as public water supply districts) in Cass County.

Q. Has the Staff reviewed the PILOT concept and the amounts in question?

A. Yes. The response noted above was reviewed on December 18, 2003 after Staff's direct testimony was submitted. The PILOT concept was explained during my interview, notes of which are contained in response to Data Request No. MPSC-549. It is my understanding that the PILOT payments were also listed and described in response to Data Request No. MPSC-598 in the last rate case.

<u>e. Depreciation and Amortization Expense</u>

Q. What is the actual depreciation and amortization expense for the twelve months ended September 30, 2003?

A. That expense is ***___________*** and is shown in Schedule MS-8.

Q. Why does this expense exist if Cass County owns the plant?

A. The plant is leased by Cass County to MEPPH under a capital lease agreement. I am advised that under Generally Accepted Accounting Principles, MEPPH incurs depreciation and amortization expense for such a capital lease.

f. Role of Cass County

Q. What is the role of Cass County, Missouri in the ownership and financing of the Aries power plant?

A. Cass County owns the plant through a bond that it issued according to Chapter 100 of the Revised Statues of Missouri. It is, therefore, a participant in the transactions that led to the financing of the Aires plant. However, as contemplated by state law, Cass County is largely a passive entity that does not control the financing of the plant or its operations.

Q. Why is Cass County the owner of the plant?

A. As explained to Staff in my interview (contained in the response to Data Request No. MPSC-549), this technique was used to enable the project to obtain property tax relief in exchange for negotiated "payments in lieu of taxes" ("PILOT" payments) that MEPPH would make to Cass County. This is a standard economic development tool that is used by Missouri local governments to attract investment. Local communities benefit from the associated economic growth associated with a project, including construction and operating jobs and payroll, associated infrastructure improvements, the PILOT payments, and future tax payments when the Chapter 100 bonds are redeemed or retired. A property tax abatement using Chapter 100 bonds was one of the incentives used by the City of Kansas City in 1996 to persuade Harley-Davidson, Inc. to build a motorcycle manufacturing plant in Kansas City.

Q. How does Cass County "ownership" of the plant affect the structure of the project?

A. Schedule MS-9 shows the Aries project structure in 1999, before Calpine participation and Cass County ownership were consummated, and at present.

g. Summary of total annual costs

Q. Based on the actual data noted above, what are the total costs for Aries?

A. The answer is shown in Schedule MS-8. The sum of fixed O&M expense, variable O&M expense, interest expense, depreciation and amortization, and a ROE (for which two values are shown) results in a total cost of ownership of ***______________________________*** the costs paid by MPS for the power purchased under the Power Sales Agreement.

Q. What are the MPS power purchase payments to MEPPH for the twelve months ended September 30, 2003?

A. As stated in Schedule MS-8, the payments are ***___________***

Q. What proportion of total plant costs do the MPS power payments represent?

A. The power payments represent ***____________*** of the total costs, depending on the ROE used.

Q. Are these proportions materially different from those provided in Staff's direct testimony?

A. Yes. Staff estimated that MPS was paying approximately 100% of the fixed costs, as can be seen by reviewing Mr. Oligschlaeger's Direct Testimony at page 11, lines 4-8; page 12, lines 5-6, 13-15, 18-20 and 21-23; and page 13, lines 2-4, 10-12 and 16-19.

Q. What is your opinion on Staff's belief that MPS is paying almost all of the fixed costs of the Aries plant but receiving less than 60% of the capacity, and that this is an example of affiliate abuse?

A. Staff's analysis is seriously flawed. It considers only the costs associated with a permanent financing that did not occur. Staff did not consider actual interest expense, O&M costs, PILOT payments to Cass County, depreciation and amortization, or a return on the equity that has been invested by the partners in the plant. Such costs are substantial and material. When those costs are properly recognized, MPS's capacity payments are less than what would result from a pro-rata allocation of actual fixed costs.

<u>h. Review of Staff Estimate of MPS Capacity Share</u>

Q. What percent of the Aries plant capacity did Staff use as the basis for a cost allocation to MPS?

A. As stated on page 16 of Mr. Oligschlaeger's Direct Testimony, "Staff developed a factor of 59.83% (derived by dividing 350 MWs by 585 MWs)." On page 17, Mr. Oligschlaeger recommended 61.31% based on an alternative methodology.

Q. Are either of these approaches an appropriate way to allocated fixed costs to MPS?

A. No.

Q. Please explain.

A. There are two issues involved with this question. One is whether fixed costs should be considered when a power supply contract is based on competitive bidding. Staff appears to want to have it both ways. On the one hand, Staff agreed that the selection of MEPPH as a result of a competitive bidding process was a reasonable result. On the other hand, Staff insists on using a cost-of-service, non-market approach to determine what it thinks

MPS should have been charged and now be allowed to recover in rates. It places MPS in a no-win situation.

The second issue is the value of summer capacity relative to winter capacity. Staff's analysis on page 16 of Mr. Oligschlaeger's direct testimony assumes no difference in economic value for the purpose of cost allocation. On page 17, an attempt is made to recognize the difference. However, the testimony on page 17 fails to recognize the higher heat rate, and therefore lower value, of the 85 MW of duct-fired capacity. Staff did not consider this significant distinction.

Q. Is capacity with the same heat rate worth more in the summer than the winter?

A. Yes. Because summer power demands significantly exceed winter demands, the need for power generating capacity is typically higher in the summer months, as is its market price. That summer peak demands exceed the winter period is shown in Schedule MS-10, which contains Southwest Power Pool non-coincident peak load data by day for calendar year 2003. The highest peak demand was on August 21, 2003 (a date during the 6-month summer period under the PSA), and is listed by SPP as 38,321 MW. The highest peak demand during the six winter months (January through March and October through December) during 2003 is 26,022 MW, or 68% of the non-coincident summer peak, on February 25, 2003. See Staff Witness David Elliott Dep. at page 13, line 13 (Jan. 8, 2004)(summer capacity is more valuable than winter capacity). This evidence is consistent with my experience as a power marketer. In order for MEPPH to offer more capacity in the summer than in the winter, and still have a reasonable expectation that it will obtain sufficient revenues from all sources to cover its costs, MEPPH needed to charge more for its summer-only capacity. And this is exactly what MEPPH did, as documented in the PSA provided in response to Data Request No. MPSC-384.

Q. What is your conclusion on the merits Staff's testimony that MPS is paying almost all of the fixed costs of the Aries plant but receiving less than 60% of the capacity?

A. As indicated above, Staff's analysis considers only the cost associated with a permanent financing that did not occur. Staff also did not consider fixed operating and maintenance costs, PILOT payments to Cass County, actual interest expense, depreciation and amortization, or a return on the equity that has been invested by the partners in the plant. This information has been provided to Staff. As was demonstrated, those costs are substantial and material. When those costs that were overlooked or not considered by Staff are recognized, MPS capacity payments are far less than what would result from a pro-rata allocation of actual fixed costs. Staff's failure to recognize those costs in its analysis invalidates Staff's conclusions.

<u>4. No disallowance of costs is appropriate when all costs are considered</u>

Q. Is any disallowance of costs appropriate when all costs are considered?

A. No. There is no justification to disallow any portion of the MPS payments to MEPPH under the PSA.

Q. Please explain.

A. First, let me reiterate that I do not believe this fixed-cost approach should be used for the reasons stated above. It is inconsistent with the Commission's Order that permitted a fair and open competitive bidding process, which is what occurred. However, if this approach is adopted, Mr. Oligschlaeger's recommendations are without factual basis. He proposed on page 17 of his Direct Testimony that MPS should be responsible for 61.31%

of the cost of the Aries plant capacity. This was an alternative to his Direct Testimony on page 16 that MPS should be responsible for 59.83% of the costs of the plant's capacity. Applying either of these allocation percentages to the actual costs of the plant results in a cost allocation to MPS that substantially exceeds the ***____________*** in payments that MPS is making to MEPPH under the PSA, as noted above. See Schedule MS-8.

In other words, because Mr. Oligschlaeger's allocations recommend that MPS be responsible for either a low figure of ***____________*** or a high figure of ***_____ _______***, Staff is in essence recommending that MPS pay more to MEPPH than what it is actually paying under the PSA.

Q. What is your recommendation based on this analysis?

A. When Staff's methodology is corrected by incorporating substantial and material fixed costs that Staff did not consider, the resulting cost allocation exceeds what MPS is paying in capacity charges under the contract. Therefore, the capacity charge is fully justified, and no disallowance of such costs in MPS rates is reasonable or appropriate.

Q. Does this conclude your testimony at this time?

A. Yes, it does.

LIST OF SCHEDULES

MS-1	Resume of Max A. Sherman
MS-2	Aquila Power Corporation Proposal to MPS dated July 6, 1998
MS-3	Aquila Power letter advising of continuing interest in supplying MPS dated November 1998
MS-4	MEP Responses to MPS on MEP Proposal
MS-5	Price change notification letter to MPS due to cost increases and decreases
MS-6	List of Data Request Responses in Aquila Data Room
MS-7	Logs of Staff Review of Data Request Responses in Aquila Data Room
MS-8	Summary of Fixed Costs for Aries Power Plant
MS-9	Aries Project Structure
MS-10	Southwest Power Pool Non-coincident Peak Load Data for 2003

SCHEDULE MS-1

RESUME OF MAX A. SHERMAN

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Core Skills: Leadership and team motivation, organization, project management, cost and schedule control, development, asset management, power marketing, public communication, and regulatory interface at federal and state levels.

Education: B.S. Engineering (Materials Science), UCLA -- 1971.
M.S. Metallurgy and Metal Processing, UCLA -- 1974.
M.S. Nuclear Engineering, University of Wisconsin -- 1975.
Introductory accounting & finance courses at Tulane University

WORK EXPERIENCE AND ACCOMPLISHMENTS

August 2003 to present Tyr Energy, Inc.

Senior Consultant performing asset management, regulatory and contract consulting services for a client with utility and "non-regulated" merchant power businesses; and a partnership that owns a merchant power plant.

November 2002 to July 2003 Centerstone Energy Partners, LLC

Partner in a startup formed to acquire, own, operate, manage, optimize and monetize power generation assets. Strategy is to take advantage of this part of the business cycle. Successes include raising capital to support bids on selected assets, being awarded an exclusive on one asset, and being short-listed on several others.

May 1996 to October 2002 Aquila Merchant Services, Inc.

Company was a top-five wholesale energy merchant that marketed and traded energy products and services (gas, power, coal, weather hedges) in North American wholesale markets. Power plant development supported the origination and trading businesses. At the peak of the trading boom, annual revenues were ~$40 billion.

1999 to 2002 Vice President, Project Development

- Led Aquila's eastern U.S. power plant development efforts in Aquila's Capacity Services business unit. Strategy was to develop and hold sites for the next business cycle. Supervised a development team to accomplish the objective. Suspended efforts when Aquila decided to exit the business.
- Led development of a $135 million, 310 MW peaking plant in Mississippi completed Summer 2002. Project was on time and on budget. Role included project structuring, cost/schedule management, economic development negotiations

with local officials, site acquisition, interconnection agreements, water and fuel supply, regulatory interface, community relations, tax abatement, contracting, development of a 24 mile transmission line, and a municipal bond financing. Obtained political support at all levels including the governor.

1999 Senior Director, Merchant Energy Partners business unit

- Led development of Aquila's first power project, a $275 million, 585 MW combined cycle plant in Missouri completed in February 2002. Assembled a development team from across and outside the organization. The team acquired the site, easements, permits, water supply, regulatory approvals, tax abatement, interconnection agreements, combustion turbines, EPC and other contracts and got the project into construction in 9½ months (half the usual time).

1996 to 1998 Director, Power Marketing

- Helped start up the power origination business for this power marketer, focusing on SPP and SERC. Role was to establish contractual infrastructure with counter parties, originating transactions, and enhancing corporate skill base as needed. Served as Aquila's lead SPP representative. Met all annual profitability targets.
- Largest transaction was Aquila's first long term toll -- 20 years on a 279 MW combined cycle generating unit with net margin valued at $22 million. This success accelerated formation of Aquila's Capacity Services business unit.

March 1993 to May 1996 Entergy Power Group

This Entergy business unit was formed to invest in domestic and overseas projects, and to own and market 809 MW of U.S. generation after it was spun out of the utility.

Manager, Business Development

- Managed Entergy's first asset-based merchant power business, Entergy Power, Inc. ("EPI"), a $175 million, 809 MW subsidiary. Had de facto P&L, budget, asset management and regulatory responsibility. Successes including achieving profitability for this merchant generating business as planned. Reported to a vice president or business unit executive.
- Led a team of power marketing professionals. Sold 400 MW long-term, plus short-term sales.
- Asset management role included control of a generating unit 100% owned by EPI, and oversight of a minority interest in a second unit. Successes included planning, funding and leading a plant overhaul which restored a unit to acceptable performance levels.

April 1980 to February 1993 -- Entergy Services, Inc. (Entergy's service company)

1991 to 1993 EPI Business Development Manager

- Assigned pricing responsibility for 809 MW of merchant capacity. Sold 140 MW under long-term contracts, plus short-term sales.

1984 to 1991 Power Transactions Administrator

- Selected as Entergy's first power marketer. Assignments included marketing capacity and energy in wholesale markets; obtaining executive approvals for transactions; tracking and reporting profitability to senior management, and managing the regulatory approval process for sales contracts.
- Accomplishments included expanding Entergy's geographic marketing reach into much of the central and southeastern U.S. Successes included 1330 MW of long term capacity sales plus numerous short-term sales.
- Grew wholesale sales to a significant portion of Entergy's business. Performance metrics included growing annual energy sales from 0.1 million MWh in 1984 to 4 - 6 million MWh; and annual pretax profit from ~$0.5 million to ~$20 million in late 1980's and ~$45-50 million in 1990's.
- Helped start up Entergy's first merchant power marketing business (EPI).

1981 to 1984 Senior Staff Technical Assistant

- Oversight role on the Grand Gulf Nuclear Station, reporting to a owner VP. Responsible for monitoring construction progress and review of all contracts with suppliers. Learned how these plants should and should not be built.
- Assigned by Chairman to supply a nuclear energy exhibit to the 1984 World's Fair. The project was on time, over funded, and made refunds to sponsors.

1980 to 1981 Fuel Market Analyst

- Responsible for evaluation and selection of nuclear fuel cycle vendors; planning and executing swaps/loans to lower inventory costs.

January 1976 to April 1980 Commonwealth Edison (now Exelon)

This Chicago utility had a large nuclear power plant fleet. It participated in a fast breeder reactor project in Oak Ridge, TN to learn how to design, build and operate the next generation of nuclear power plants.

Components Engineer

- Managed contractor design, fabrication and delivery of $100 million of Clinch River Breeder Reactor Plant equipment, and related R&D programs. Equipment (tanks, vessels, heat exchangers, pumps) was built on time and under budget. Developing project management skills was essential to success of these projects.

Summers 1971 to 1974 Los Alamos Scientific Laboratory

Summer Staff Scientist

- Performed research into fusion reactor materials design and development

<u>1971 to 1973 University Cooperative Housing Association</u> <u>(UCLA housing coop)</u>

Member, Board of Directors

- Owner's Representative on a dormitory construction job next to UCLA campus.

Professional: Former member, Engineering & Operating Committee, Southwest Power Pool
Past Chairman, Commercial Practices Committee, SPP
Former member, SPP Regional Pricing Working Group
Past Chairman, Louisiana Nuclear Society.

SCHEDULE MS-2

AQUILA POWER CORPORATION PROPOSAL

TO

MISSIOURI PUBLIC SERVICE

DATED JULY 6, 1998

Aquila Power
10750 East 350 Highway
P.O. Box 11739
Kansas City, MO 64138
816-936-8712
Fax: 816-936-8775
msherman@utilicorp.com

AQUILA ENERGY

July 6, 1998

Max A. Sherman
Director
Power Marketing

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

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

Dear Mr. Harris:

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

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

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

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

Mr. Kiah Harris
Burns & McDonnell
July 6, 1998

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

Very truly yours,

Max Sherman

Max Sherman
Director, Power Marketing

Enclosure

cc: David Stevenson
Jeff James

TABLE OF CONTENTS

AQUILA POWER CORPORATION PROPOSAL

TO

MISSOURI PUBLIC SERVICE

EXECUTIVE SUMMARY

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

- Term: Various terms are offered from June 1, 2000 through May 31, 2004, with buyout options for the last 2 contract years.
- Type of Service: Unit power with a 93% minimum guaranteed annual equivalent availability.
- Designated Unit: A nominal 267 MW combined cycle generating unit to be constructed by LS Power LLC at an industrial park at the Entergy/TVA border in Batesville, Mississippi. The unit is fully permitted. Initial financing and breaking ground to start construction is expected to start in late July 1998. Aquila Power has executed a contract to purchase the capacity and the right to toll energy from the unit for a term well beyond the period requested by the subject RFP.
- Capacity price: We have priced the capacity at the site, and provided a number of transmission options to move the power and associated energy to MPS' system. The least cost firm transmission path from the project to MPS, across Entergy and Ameren, is presently ~$2.00/kW-month. The capacity prices under various options are shown below:

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

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

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

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

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

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

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

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

DESIGNATED GENERATING UNIT

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

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

Major Permits and Approvals for Batesville Project

- Public Service Commission of Mississippi Certificate of Public Convenience and Necessit Docket No. 97-UA-513, dated December 12, 1997
- State of Mississippi Air Pollution Control Permit No. 2100-00054, dated November 25, 199 (both permission to construct and permission to operate)
- National Pollutant Discharge Elimination System (NPDES) Permit No. MS0052931, date December 12, 1997
- Mississippi Permit to Divert or Withdraw for Beneficial Use the Public Waters, Permit Nc MS-SW-02744, dated November 25, 1997.
- Federal Energy Regulatory Commission Certification of Exempt Wholesale Generato Status, Docket No. EG98-59-000, dated April 28, 1998.
- U.S. Army Corps of Engineers Nationwide/General Permit Nos. NW07, NW12, NW2 NW26 and GP22, issued December 4, 1997.
- City of Batesville, MS Confirmation of Appropriate Zoning, dated April 24, 1997.

Copies of these permits can be provided upon request.

TERM

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

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

Option 2 (75 MW)
June 1, 2000 through May 31, 2001

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

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

QUANTITY

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

Option 1: 100 MW for summer 2000 (June 1, 2000 through September 30, 20(
75 MW for non-summer months (October 1, 2000 through May 31,

Option 2: 75 MW June 1, 2000 through May 31, 2001

Option 3: Up to 100 MW for the last three (3) contract years (June 1, 2001 thrc
May 31, 2004)

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

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