Exhibit No.:	*1065*
Issue:	*Aries Unit*
Witness:	*Mark L. Oligschlaeger*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Rebuttal Testimony*
Case Nos.:	*ER-2004-0034*

Date Testimony Prepared: *January 26, 2004 modified Februrary 27, 2004*

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY SERVICES DIVISION

REBUTTAL TESTIMONY

OF

MARK L. OLIGSCHLAEGER

AQUILA, INC. D/B/A

AQUILA NETWORKS MPS-ELECTRIC

CASE NO. ER-2004-0034

Jefferson City, Missouri
January 2004

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 MARK L. OLIGSCHLAEGER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Mark L. Oligschlaeger, of lawful age, on his oath states: that he has participated in the preparation of the following rebuttal testimony as modified on February 27, 2004, in question and answer form, consisting of 36 pages to be presented in the above case; that the answers in the following rebuttal 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.

Mark L. Oligschlaeger

Mark L. Oligschlaeger

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

Toni M Charlton

Notary Public

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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REBUTTAL TESTIMONY OF

MARK L. OLIGSCHLAEGER

AQUILA, INC.

d/b/a AQUILA NETWORKS-MPS-ELECTRIC

CASE NOS. ER-2004-0034

ARIES UNIT 20

REBUTTAL TESTIMONY

OF

MARK L. OLIGSCHLAEGER

AQUILA, INC.

d/b/a AQUILA NETWORKS-MPS-ELECTRIC

CASE NO. ER-2004-0034

Q. Please state your name and business address.

A. Mark L. Oligschlaeger, P.O. Box 360, Suite 440, Jefferson City, MO 65102.

Q. Are you the same Mark L. Oligschlaeger who has previously filed direct testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of this testimony is to address the direct testimony filed by Aquila, Inc. (Aquila/UtiliCorp or Company) d/b/a Aquila Networks – MPS (MPS) witnesses Lisa A. Starkebaum and Jerry G. Boehm on the issue of the Aries Unit Purchased Power Agreement.

Pages 2 through 19 intentionally left blank

<u>ARIES UNIT</u>

Q. Has the Company made an adjustment to annualize the capacity charges associated with MPS' purchase of power from the Aries Generating Unit?

A. Yes, it has. Company witness Starkebaum sponsors Aquila/UtiliCorp's adjustment to annualize capacity charges associated with MPS purchased power agreements (PPAs) at page 12 of her direct testimony. She states that the Company's adjustment includes an annualization of Aries capacity charges.

A general description of the Aries PPA can be found on pages 7-8 of Company witness Boehm's direct testimony.

Q. What level of capacity charges associated with the Aries unit has Aquila/UtiliCorp included in its case?

A. The Company has reflected an annualized level of $27.66 million.

Q. Does the Staff agree that $27.66 million is an appropriate level to include in rates for Aries capacity charges?

Q. No. Because MPS is purchasing power from the Aries unit through an affiliated entity (Merchant Energy Partners – Pleasant Hill, or MEPPH), the Staff believes it is appropriate to price the capacity from the Aries unit on a "lower of cost or market" basis. Because the cost of the Aries capacity to MPS's affiliated supplier is less than the market value paid by MPS for that power, MPS's rates should reflect only the cost to Aquila of the Aries unit capacity. The quantification of this adjustment, and a more detailed explanation for its rationale, can be found in my direct testimony in this proceeding.

Q. Why did Aquila/UtiliCorp make the decision for its MPS division to obtain power through a purchased power agreement (PPA) with an affiliated entity?

A. The Staff believes this decision was made because the Company believed it could earn higher profits by having a non-regulated affiliated entity construct a power plant and sell power to MPS through a PPA, than having MPS construct the power plant for itself.

Q. Generally, what are an electric utility's options for obtaining additional power to meet load growth or to replace existing power sources?

A. Generally, electric utilities have the option of either building their own generating units to provide power for their customers or purchasing a portion of the output of a generating unit owned by another electric provider.

Historically, when an electric utility builds its own generating unit, it typically intends to use most of the power generated by that unit for the utility's native load customers. Some of the unit's output may be sold to neighboring utilities to meet their power needs, and excess energy during non-peak periods may also be sold to utilities in the interchange market. For ratemaking purposes, this Commission has placed in rate base the net original cost of constructing utility-owned units, and allowed a return on that amount in setting rates for those utilities. Depreciation expense is booked to charge the cost of the units to expense on the utility's income statement ratably over time. This allows the utility to earn a return "on" its investment in rate base, and to recover a return "of" the investment through depreciation.

Alternatively, if a utility does not wish to construct and own generating units, it may choose to either purchase capacity from a portion of the power produced by a generating unit owned by another entity, or acquire power from a utility which has purchased power from another entity – a "purchase for resale" transaction. In this case, the utility buying the power is char0ged a price for that power reflecting both the capital costs of the unit producing the power (the capacity or demand charge), and the incremental price of generating that power (the energy charge). However, the entire amount paid by the purchasing utility for its share of power is typically charged to purchased power expense on its books.

Another potential difference between ownership of a power plant, and purchasing power from an outside entity is the term of the commitment. When a utility builds a power plant, normally its intends to have the plant provide power for native load customers over the useful life of the plant (generally 35-40 years or more). In contrast, agreements to purchase power may be either short-term (i.e., one to five years) or long-term (20 years or more).

Q. When a utility builds generation to serve native load customers, is utility ownership of that plant the only option available for that utility?

A. No. A utility choosing to build generation has the option of constructing the unit, selling it to a third party, and then leasing the unit back from the new owner. The lease payments charged by the new owner would again be based on the capital costs of the leased unit, as well as the incremental cost of producing energy from the plant. The utility taking power from the leased unit would charge the lease payments to lease expense on its books.

Q. When a utility takes power from a leased plant, as opposed to owning the plant, how would the amount of the lease payments compare to the amount of rate recovery the utility would receive from placing the unit in question in rate base?

A. Conceptually, the amounts should be similar, as both rate recovery of lease expense and rate recovery of amounts associated with placing generating plants in rate base are premised upon recovery of the capital and expense components of producing power, which will be identical whether the unit is owned or leased. However, there usually are some differences between the method by which lease payments are calculated for rate purposes and how revenue requirement is calculated for generating plants included in rate base. Because the return on rate base component of power plant costs is calculated on the undepreciated component of the plant costs at a point in time, this results in declining cost recovery over time as the undepreciated amount of plant costs declines over time. In contrast, lease payments are normally calculated on a levelized basis; that is, calculating the total return on and of capital costs over a unit's life and spreading that amount equally over the life of the lease. In addition, a lease term may not be the same as the expected life of the generating unit put into rate base and, therefore, the capital cost recovery component of the lease payment may not be the same as the revenue requirement for the unit that would be reflected in rates if the unit were afforded rate base treatment.

Q. Does Aquila/UtiliCorp own or lease the Aries unit?

A. Yes. Aquila/UtiliCorp leases the Aries unit. As discussed in my direct testimony, Aquila/UtiliCorp has chosen to provide the title to the Aries unit to Cass County, Missouri, and then lease the plant from Cass County.

Q. Has MPS obtained power in the past through leasing of generating units?

A. Yes. MPS, while it has constructed generating units at its Greenwood and Ralph Green locations in the past, chose to sell those units to third parties and then obtain power from the plants through long-term lease arrangements.

Q. Why would a utility choose to lease a generating unit rather than own it directly?

A. In the mid to late-1970s, when MPS chose to lease the Greenwood and Ralph Green generating units, it is the Staff's understanding that MPS took that course of action because it was experiencing financial difficulties at that time, and did not want to reflect additional debt on its balance sheet associated with ownership of these units. Today, a utility may choose to enter into a leasing arrangement because it expects to achieve a higher return associated with its generating plant investment through leasing the plant rather than having the cost of the unit reflected in rate base. In that case, a utility may believe that it could achieve greater profits from the unit if it was unregulated rather than be held to the regulated rates of return authorized by public utility commissions. As will be discussed later in this testimony, the desire for higher returns is the rationale for Aquila/UtiliCorp's decision to lease the new Aries unit and this arrangement is an abuse of affiliate relationships.

Q. Has Aquila/UtiliCorp provided any information to justify its choice to purchase generating capacity through a PPA with an affiliated entity rather than building its own generating unit?

A. Yes. Case No. EM-99-369 was Aquila/UtiliCorp's application for the Commission to make certain determinations required under the Public Utilities Holding Company Act of 1935 respecting the contract between MPS and MEPPH for supply of power from the Aries unit. In that proceeding, Aquila/UtiliCorp provided the Staff an analysis that purports to demonstrate that the costs to MPS of entering into a five-year lease to obtain power is less expensive than MPS owning the unit and rate basing it, over the five-year term of the lease.

Q. From MPS's perspective, why might obtaining power through a PPA be more economical than including the unit in rate base?

A. There are two basic reasons why a PPA might show a cost advantage. First, as previously discussed, lease payments are typically based on levelized recovery of capital costs, as opposed to the front-loaded recovery of the return component of the generating unit caused by rate base treatment. This is also typical for the capacity cost recovery in a PPA.

Second, the purchased power agreement MPS entered into calls for the Company to pay for 500 MW of power during peak periods, but a reduced amount of power during non-peak periods. Rate base treatment would result in MPS customers being responsible for the entire cost of the plant.

Q. Because of these factors, wouldn't the MPS PPA inherently be less expensive than rate basing the Aries unit?

A. Not necessarily.

In regard to levelized cost recovery of capital costs under a PPA, the levelized cost should be calculated in such a way that customers would be indifferent between paying rates based on the traditional declining cost rate base methodology, or rates based on levelized PPA cost recovery, over the life of the unit in question.

Concerning the point that rate base treatment would mean the full cost of the Aries unit would be reflected in customer rates, that cost would be offset under the normal ratemaking process by the proceeds of interchange sales made from the Aries unit during off-peak periods (i.e., MPS's ability to sell power during off-peak periods due to its reduced need for power during that time). One would have to know the amount of projected interchange sales, and the estimated proceeds from those sales before reaching a firm conclusion on whether rate basing or leasing the unit would be more economical from a ratepayer viewpoint.

Q. Is the five-year period of the PPA an appropriate time frame in which to assess the benefits of the PPA versus owning the Aries unit?

A. No. Because ownership of the unit has long-term consequences, with most units having an expected useful life of 30 years or more, an evaluation of whether it is economically better to own a unit or purchase power from it should extend far beyond an initial five-year lease period. In fact, use of this five-year period to justify the decision to purchase power from the Aries unit is inherently biased against the ownership option; again, because of the levelized capital cost recovery feature of PPA cost recovery.

Q. In the Staff's view, has MPS done an adequate job of justifying its decision to purchase power from the Aries unit, as opposed to MPS owning the unit?

A. No.

Q. Did the Company seriously give consideration to the option of having MPS build a generating unit to meet its need for power beginning in 2001?

A. No. In the Staff's notes of the interview of Mr. Frank DeBacker (Aquila/UtiliCorp's Vice-President of Fuel and Purchased Power in 1998-1999) and Mr. Robert Holzwarth (Aquila/UtiliCorp's Vice-President of Power Services in 1998-1999), it is stated that Mr. DeBacker and Mr. Holzwarth were knowledgeable of a clear understanding from the Company's management at the time the Aries decision was made that Aquila/UtiliCorp's regulated electric divisions were not to construct power plants; and that these divisions' power needs were to be met through short-term PPAs.

As mentioned in my direct testimony, Mr. DeBacker and Mr. Holzwarth were given the opportunity to review the Staff's notes of the interview and make any corrections, additions or clarifications in the response to Staff Data Request No. 548.

Q. Does the Staff have additional concerns with the Company's decision to lease the Aries unit?

A. Yes. The Staff believes the short term of the PPA (five years) exposes MPS customers to greater risks associated with future market based pricing of power than they would if MPS owned the Aries unit.

Q. Please explain in general terms the concept of "market-based pricing" of power.

A. "Market-based" pricing of power represents charging customers for power they use based upon a price determined in a competitive marketplace of buyers and sellers. This contrasts with treatment of generating units afforded under traditional regulation, in which customers are charged rates based upon the actual capital and operating costs associated with the units that are dedicated to native load customers. The market price of power at any point in time may be higher or lower than the actual "embedded" price of power charged to customers in electric rates under current regulation.

Q. What factors would cause the market price of power to either be higher than or lower than the embedded costs of power reflected in rates?

A. Because generating units are long-lived assets, customers are likely to pay the capital costs associated with any particular unit for an extended period of time (i.e., 30-40 years). If the cost of generating power from newer units and power generation technologies is declining over time compared to the embedded cost of a utility's existing generating units, then the market price of power will be less than that utility's embedded generating costs. Alternatively, if the cost of generation from new units is increasing relative to the embedded cost of generation for a utility, then the market price of power will be greater than that utility's embedded generation costs. Accordingly, customers are not inherently benefited or harmed by the introduction of market-based pricing of electricity. However, customers are exposed to greater risk under market-based generation pricing.

Q. Why is market-based pricing riskier from a customer perspective?

A. It is riskier because customers will face more volatility in rates for power under market-based pricing schemes than under the traditional embedded cost regulatory pricing approach. As previously discussed, once a generating unit is operational and included in a utility's rate base, the capital cost component of that unit's cost that is reflected in rates will be highly predictable over the life of the unit. In contrast, the capital cost component of market based electricity prices will be subject to frequent fluctuation based on trends in the generation marketplace.

To use an example, if a utility provides electricity to its customers from one generating unit only, the capital cost portion of electricity from that unit will be largely fixed in advance over the life of the unit for 30 or 40 years, or more. Though rates charged to customers for the capital costs of that unit may change over time, due to the "declining-cost" nature of capital recovery in rates, those changes are highly predictable. In contrast, the capital cost component of that utility's generation rates might be subject to material and unanticipated changes on a frequent basis, if rates to its customers are based upon market prices for generation.

For this reason, utility customers inherently face more risk of unexpected pricing changes when market prices determine the rates they pay for electric service, as opposed to the embedded costs of the generating units serving them.

Q. Please explain how MPS's contract to obtain power from the Aries unit is an example of market-based pricing of power.

A. While the Aries unit is expected to have a lengthy life typical of a generating unit, the contract only obligates Aries' owners to provide power to MPS for a five-year period. At the end of the five years, MPS must either reach a new agreement with the Aries unit's owners to obtain additional power, or replace the power it obtained from the Aries unit with another source. While the Aries owners may choose to again bid to supply power to MPS customers when the five-year term of the current agreement has expired, they are not obligated to do so. Even if power is continues to be supplied to MPS through another Aries PPA after the five-year term of the initial PPA has expired, MPS customers will still face the risk of changes in the market price of power in the new contract. If a new five-year PPA with the Aries unit is agreed to starting in 2005, then MPS' customers will face the same risks five years later in 2010.

Q. Has there a general trend towards greater market pricing of electric power in this country in the recent past?

A. Yes, though generally this trend is tied to overall electric restructuring efforts in various jurisdictions. In other words, those jurisdictions that have chosen to allow customers greater choice in the selection of their electricity provider as a necessary consequence also allow customers greater exposure to market pricing for generation service. Whether electric restructuring is a worthy goal for pursuit is, of course, a policy judgment to be made by legislatures and regulatory bodies. The Staff believes that neither the Commission nor the Missouri Legislature has established a policy encouraging either electric restructuring or greater market pricing of power to native load customers in Missouri.

Changes in the electric industry in recent years related to such factors as California restructuring difficulties, the Enron bankruptcy and the financial problems of electric bulk energy marketers have led to a significant slow down in electric restructuring initiatives. Accordingly, the trend towards greater use of market pricing of power has also recently decelerated as well.

Q. Do electric utilities benefit from market-based pricing of generation service?

A. Electric utilities can conceivably achieve higher profitability levels charging market-based rates compared to traditional embedded ratemaking, when the generation services are performed by non-regulated affiliates providing capacity power to the regulated entity under some form of contract arrangement, such as the case with the Aries PPA. Again, this potential benefit depends upon the long-term trend in market prices for power compared with the embedded cost of power production.

Q. Has Aquila/UtiliCorp undertaken a policy in the past of attempting to move toward market pricing of generation?

A. Yes. Several years ago, the Company had the opportunity to place its Greenwood Units 1 and 2 in rate base upon the expiration of the long-term lease arrangements it had in place for the two units in the mid- to late–1970s. However, when Aquila/UtiliCorp exercised its option to purchase these units, it chose to place them in a non-regulated subsidiary, to enter into new leasing arrangements with the affiliated entity (MPS), and to continue to obtain power from these units for MPS customers at a new, and higher, lease rate. The Staff's concerns regarding this situation with the Greenwood units were discussed in more detail in the direct testimony of Staff witness Featherstone in Case No. ER-2001-672.

The Staff believes Aquila/UtiliCorp has attempted to implement a policy of no longer including in rate base the generating units it constructs to provide electric power for its native load customers in its regulated divisions. For example, the Company made an attempt in Case No. EM-97-395 to have all of its existing MPS regulated generating units placed in an unregulated EWG. (The case was later withdrawn.) Aquila/UtiliCorp's proposals in Case No. EM-97-395, the recent history of the Greenwood units and the Company's decisions regarding the Aries unit all demonstrate this policy of attempting to move generation resources to Aquila/UtiliCorp's non-regulated side. Such a policy raises concerns regarding affiliate abuse.

Q. Why has Aquila/UtiliCorp moved towards market-based pricing of power?

A. Based upon its response to Staff Data Request No. 365 in Case No. ER-2001-672, the Company implemented this policy to allow it to achieve greater profit levels. The response to Staff DR No.365 states, "[t]he Company believes that the current regulatory climate does not warrant the business risks associated with constructing and owning rate-based generating plants". The Staff interprets this statement to mean that Aquila/UtiliCorp perceived at the time of this response that current return on equity levels earned on rate base investments were inadequate, and that greater returns could be garnered through the lease of power plants by affiliates and the purchase of power from these affiliates at "market" rates. This policy of moving generation from the regulated utility to the non-regulated affiliate and charging the utility a higher price is an abuse of the affiliate relationship.

Q. All other things being equal, if the Company can earn greater returns on its generation investment by selling power to customers at market rates, what would be the impact on MPS's customers?

A. All other things being equal, this means Aquila/UtiliCorp's native load MPS customers over the long-term would pay higher rates related to "market-based" PPAs for purchased power than they would pay if MPS's rates were based on embedded cost ratemaking for those units.

Q. Is it possible at this time to determine whether this Aquila/UtiliCorp policy of not placing new generating units in rate base was in the best interest of MPS ratepayers?

A. Any such conclusion cannot be reached in the absence of a study comparing the benefits and risks of direct ownership of units by MPS to obtaining power through lease arrangements and PPAs. However, there are a number of indications that Aquila/UtiliCorp expected the future price of power to increase, at least in the short-term; at the time the Aries decision was made. If the Company's expectations are correct, the decision to purchase power from the Aries unit as opposed to ownership of the unit by MPS may not be in the best interest of MPS customers.

Q. What indications are you referring to?

A. The above answer is based on the following points:

1.) The Staff is aware of a number of power price forecasts utilized by the Company that showed an expectation of sharply higher power prices through time.

2.) The market cost of replacing power obtained through a lease of the Greenwood Units 1 and 2 several years ago was in excess of the prior leased cost, as well as in excess of the cost of power from these units if these units were included in rate base.

Each of these points will be addressed in more detail below.

Q. What is your basis for asserting that the Staff has reviewed Company power price forecasts that show significantly higher power prices into the future?

A. In its review of the Aries PPA issue in the last MPS electric rate proceeding in Missouri (Case No. ER-2001-672), as well as the instant case, the Staff has become aware of the existence of several power price forecasts prepared by Aquila/UtiliCorp that indicated sharply higher market prices of power were expected in future years. These forecasts were prepared in the period of the late 1990s to the early years of this decade.

Q. What is the significance of these power price forecasts?

A. If a regulated utility expects escalating power prices into the future, it would seem to be logical for that utility to hedge against higher power prices by owning and controlling its own generating units, as opposed to relying on short-term PPAs and exposing your customers to the risk of frequent power price increases.

Q. What was the situation concerning the price of power MPS is obtaining from Greenwood Units 1 and 2?

A. As previously mentioned, upon the expiration of the long-term leases from which MPS formerly obtained power from these units, Aquila/UtiliCorp chose to purchase these units from the owners, place the units in an unregulated subsidiary, and then enter into a new lease for the supply of power to MPS customers. The new lease costs were: (1) substantially higher than the cost of power to MPS from these units under the recently expired lease; and (2) substantially higher than the cost of power from these units if those costs had been based upon traditional rate base treatment of those units

Q. Does the fact that a utility decides to place ownership of generating facilities in an unregulated affiliate necessarily mean that the unregulated affiliate must charge the affiliated regulated entity a market price for power?

A. No, such affiliate abuse is not necessary. This is demonstrated by the Kansas City Power & Light Company (KCPL) Application for Commission approval of its corporate restructuring, docketed as Case No. EM-2001-464. In that case, KCPL received permission to form a holding company named Great Plains Energy, Incorporated (GPE). KCPL (the regulated utility) will retain all of its existing generating assets. Under the holding company structure, GPE proposed to place its future generating needs in an unregulated affiliate company, Great Plains Power, Inc. (GPP). However, the Stipulation and Agreement in Case No. EM-2001-464 called for any power sold to KCPL from certain generating units owned by GPP in the future would be sold at cost-based rates, so that the cost of power paid by KCPL would be equivalent to the costs paid by customers under traditional cost-of-service based rates. The Commission approved this Stipulation and Agreement, using the following language:

> In January of 2001, KCPL entered into a binding memorandum of understanding with General Electric Company under which KCPL may lease or purchase up to five combustion turbine generating units. Each of these units has a generating capacity of 77 MW. These turbines will not be completed until 2003. If the proposed reorganization is approved, KCPL anticipates seeking Commission approval to transfer

> its rights under the memorandum of understanding to GPP. KCPL anticipates that it will need an additional 231 MW of generation capacity in the next three years, that is, the generating capacity of three of the five combustion turbines. KCPL currently purchases less than five percent of its energy needs on the open market. If the proposed reorganization is approved, KCPL may enter into a cost-based purchase supply agreement with GPP to acquire this additional capacity. Such a cost-based purchase supply agreement would provide power at a cost to ratepayers identical to costs under traditional cost-of-service based rates. The cost of power generated by a combustion turbine owned by GPP would be essentially identical to the cost of power generated by a combustion turbine owned directly by KCPL.

Order Approving Stipulation and Agreement and Closing Case, pp. 7-8.

Q. What is the Staff's overall policy recommendation in this proceeding regarding the Aries unit?

A. The Staff has seen no evidence that Aquila/UtiliCorp has ever performed an adequate analysis to compare the long-term cost of direct ownership of the Aries unit with the cost of obtaining power from that plant through short-term PPAs. What evidence exists at this point does indicate, however, that the Company has expected and still expects the price of power in the marketplace to increase over time. If that is true, then MPS customers may have been better off being able to utilize Aries power over its expected useful life as a Commission regulated asset, rather than periodically having to obtain higher priced power from sources elsewhere, or by paying for power from the Aries unit periodically "marked-up" to reflect current market pricing.

The Company is currently in the process of receiving and evaluating bids concerning its power needs subsequent to the expiration of the current Aries unit PPA. At this time, the Staff recommends that the Commission order Aquila/UtiliCorp to explicitly consider MPS's ownership of a generating unit (and, consequently, rate base treatment of the unit) as a potential source of power beyond 2005, and as an alternative to continued receipt of power through affiliated lease arrangements and short-term affiliated PPAs. Such an analysis should be at least as detailed as that which is addressed in the Commission's suspended electric utility resource planning rules, 4 CSR 240-22.010-.080. The analysis should also be of a long-term nature, in order to fully and fairly assess the benefits and detriments of MPS's options for obtaining future capacity, including utility ownership of power plants. Only if Aquila/UtiliCorp is ordered to do this will the Commission be able to adequately review and evaluate in future rate proceedings the necessary evidence as to whether MPS is seeking recovery of an excessive level of expense to compensate it for power provided to its customers.

Q. Has the amount of the Staff's proposed adjustment for test year Aries capacity charges changed since the filing of the Staff's direct testimony?

A. No. The Company has provided the Staff with certain additional information regarding Aries costs during the prehearing conference to this case. The Staff is still in the process of evaluating this information. If this or other information leads the Staff to revise its Aries adjustment amount, the Commission and the parties to this proceeding will be informed of these changes promptly.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

Summary of Synergy Benefits, net of Costs to Achieve

UtiliCorp/Saint Joseph Light and Power

(Dollars in Current 000's)	2001	2002	2003	2004	2005	First Five Full Years Total	Average Years 1-5	2006	2007	2008	2009	2010	Years 6-10 Totals	Average Years 6-10	Ten Full Years Totals	Average
I Operating Costs Current Dollars																
1 Dispatching/Generation Savings See I.1	$ 3,820	$ 4,358	$ 5,196	$ 6,021	$ 6,687	$ 26,082	$ 5,216	$ 7,817	$ 6,502	$ 7,274	$ 6,557	$ 5,733	$ 33,883	$ 6,777	$ 59,965	$ 5,997
2 General & Administrative Savings See I.2	$ 5,193	$ 5,599	$ 5,739	$ 5,882	$ 6,029	$ 28,442	$ 5,688	$ 6,180	$ 6,334	$ 6,493	$ 6,655	$ 6,822	$ 32,484	$ 6,497	$ 60,926	$ 6,093
3 Distribution Savings	$ 1,385	$ 1,821	$ 1,965	$ 2,014	$ 2,064	$ 9,249	$ 1,850	$ 2,116	$ 2,169	$ 2,223	$ 2,279	$ 2,336	$ 11,122	$ 2,224	$ 20,370	$ 2,037
4 Transmission Savings	$ 315	$ 548	$ 562	$ 576	$ 590	$ 2,591	$ 518	$ 605	$ 620	$ 636	$ 652	$ 668	$ 3,180	$ 636	$ 5,772	$ 577
5 Conversion to UtiliCorp Benefits See I.5	$ 1,996	$ 3,022	$ 2,976	$ 3,401	$ 3,626	$ 15,021	$ 3,004	$ 3,876	$ 4,152	$ 4,454	$ 4,728	$ 5,003	$ 22,213	$ 4,443	$ 37,234	$ 3,723
6 Total O&M	$ 12,709	$ 15,348	$ 16,437	$ 17,894	$ 18,997	$ 81,385	$ 16,277	$ 20,594	$ 19,777	$ 21,079	$ 20,870	$ 20,561	$ 102,882	$ 20,576	$ 184,267	$ 18,427
II Capital Savings (Costs):																
1 Depr - Interconnect/SCADA/T&D See II 1	$ (285)	$ (330)	$ (324)	$ (318)	$ (313)	$ (1,570)	$ (314)	$ (307)	$ (302)	$ (296)	$ (290)	$ (330)	$ (1,525)	$ (305)	$ (3,095)	$ (310)
2 Amort of Transaction/Transition Costs	$ (1,509)	$ (1,509)	$ (1,509)	$ (1,509)	$ (1,509)	$ (7,545)	$ (1,509)	$ (1,509)	$ (1,509)	$ (1,509)	$ (1,509)	$ (1,501)	$ (7,537)	$ (1,507)	$ (15,082)	$ (1,508)
3 Return on Interconnect SCADA /T&D	$ (896)	$ (897)	$ (841)	$ (786)	$ (731)	$ (4,152)	$ (830)	$ (677)	$ (624)	$ (571)	$ (519)	$ (463)	$ (2,854)	$ (571)	$ (7,006)	$ (701)
4 Return on Transaction/Transition Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5 Total Capital Savings (Costs)	$ (2,690)	$ (2,736)	$ (2,674)	$ (2,613)	$ (2,553)	$ (13,267)	$ (2,653)	$ (2,493)	$ (2,435)	$ (2,376)	$ (2,318)	$ (2,294)	$ (11,916)	$ (2,383)	$ (25,183)	$ (2,518)
															$ -	$ -
III Total Synergies, net of Cost to Achieve	$ 10,019	$ 12,612	$ 13,763	$ 15,281	$ 16,443	$ 68,118	$ 13,624	$ 18,101	$ 17,342	$ 18,703	$ 18,552	$ 18,267	$ 90,966	$ 18,193	$ 159,084	$ 15,908
IV Enterprise Support Functions Allocated (In) Current Dollars																
1 SJLP Direct Costs transferred to ESF See I.2	$ 2,292	$ 2,350	$ 2,409	$ 2,469	$ 2,530	$ 12,050	$ 2,410	$ 2,594	$ 2,659	$ 2,725	$ 2,793	$ 2,863	$ 13,633	$ 2,727	$ 25,683	$ 2,568
2 SJLP Direct Costs transferred to IBU	$ 922	$ 1,212	$ 1,308	$ 1,341	$ 1,374	$ 6,157	$ 1,231	$ 1,409	$ 1,444	$ 1,480	$ 1,517	$ 1,555	$ 7,404	$ 1,481	$ 13,561	$ 1,356
3 Support Functions Allocated (In)	$ (12,375)	$ (12,685)	$ (13,002)	$ (13,327)	$ (13,660)	$ (65,049)	$ (13,010)	$ (14,002)	$ (14,352)	$ (14,710)	$ (15,078)	$ (15,455)	$ (73,597)	$ (14,719)	$(138,645)	$(13,865)
4 Net Allocations (costs) savings to SJLP	$ (9,161)	$ (9,123)	$ (9,265)	$ (9,517)	$ (9,755)	$ (46,842)	$ (9,368)	$ (9,999)	$ (10,249)	$ (10,505)	$ (10,768)	$ (11,037)	$ (52,559)	$ (10,512)	$ (99,401)	$ (9,940)
V Total Synergies, net of Costs to Achieve and Allocated Costs	$ 858	$ 3,489	$ 4,478	$ 5,764	$ 6,688		$ 4,255	$ 8,101	$ 7,093	$ 8,198	$ 7,784	$ 7,230		$ 7,681		
VI Premium Costs																
1 Return on Premium See IV:1	$ (10,203)	$ (9,941)	$ (9,680)	$ (9,418)	$ (9,156)	$ (48,399)	$ (9,680)	$ (8,895)	$ (8,633)	$ (8,371)	$ (8,110)	$ (7,848)	$ (41,857)	$ (8,371)	$ (90,256)	$ (9,026)
2 Amortization of premium	$ (2,302)	$ (2,302)	$ (2,302)	$ (2,302)	$ (2,302)	$ (11,510)	$ (2,302)	$ (2,302)	$ (2,302)	$ (2,302)	$ (2,302)	$ (2,302)	$ (11,510)	$ (2,302)	$ (23,020)	$ (2,302)
3 Reflect non-tax deductibility of premium	$ (1,535)	$ (1,535)	$ (1,535)	$ (1,535)	$ (1,535)	$ (7,673)	$ (1,535)	$ (1,535)	$ (1,535)	$ (1,535)	$ (1,535)	$ (1,535)	$ (7,673)	$ (1,535)	$ (15,347)	$ (1,535)
4 Total Premium cost	$ (14,040)	$ (13,778)	$ (13,516)	$ (13,255)	$ (12,993)	$ (67,582)	$ (13,516)	$ (12,731)	$ (12,470)	$ (12,208)	$ (11,946)	$ (11,685)	$ (61,041)	$ (12,208)	$(128,623)	$(12,862)
VII SJLP share of premium costs	$ (7,020)	$ (6,889)	$ (6,758)	$ (6,627)	$ (6,497)		$ (6,758)	$ (6,366)	$ (6,235)	$ (6,104)	$ (5,973)	$ (5,842)	@50%	$ (6,104)		
VIII Synergies, net of 50% of premium (Line V less VII)	$ (6,162)	$ (3,400)	$ (2,280)	$ (864)	$ 192		$ (2,503)	$ 1,736	$ 858	$ 2,094	$ 1,811	$ 1,388		$ 1,577		

See Appendix VJS-A for details of calculations.

Shared synergies Master 1011 NHome Inflated.xls

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Schedule 1

VJS-1
ANNUAL DETAIL