Exhibit No.: 023
Issues: Resource Planning, Joint Dispatch and Fuel and Purchased Power Prices
Witness: H. Davis Rooney
Sponsoring Party: Aquila Networks-MPS & L&P
Case No.: ER-

Before the Public Service Commission
of the State of Missouri

Direct Testimony

of

H. Davis Rooney

****Denotes Highly Confidential Information****

NP

TABLE OF CONTENTS
DIRECT TESTIMONY OF H. DAVIS ROONEY
ON BEHALF OF AQUILA, INC.
D/B/A AQUILA NETWORKS-MPS AND AQUILA NETWORKS-L&P
CASE NO. ER-________

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI
DIRECT TESTIMONY OF H. DAVIS ROONEY
ON BEHALF OF AQUILA, INC.
D/B/A AQUILA NETWORKS-MPS AND AQUILA NETWORKS-L&P
CASE NO. ER-________

Q. Please state your name and business address.

A. My name is Davis Rooney. My business address is 10750 E. 350 Highway, Kansas City, MO 64138.

Q. What is your occupation?

A. I am employed by Aquila, Inc. ("Aquila" or "Company") as Director of Resource Planning.

Q. Would you briefly describe your educational training and professional background?

A. I graduated from the University of Kansas. I received a B.A., with distinction, in Mathematics (1982), and a B.S., with distinction, in Business (1983), with majors in Accounting and Business Administration and a concentration in Computer Science. I obtained my Certified Public Accountant certificate in 1983 and practiced in public accounting from 1983 to 1992. In 1992 I joined Aquila as Controller of its WestPlains Energy division and have held several positions focused on financial management and analysis including Director of Accounting and Finance for the Missouri Electric divisions of Aquila Networks.

Q. How is your direct testimony organized?

A. My direct testimony is organized as follows:

I. MPS and L&P Electric Operations and Resources During 2005

II. Annualized Fuel & Purchased Power Expense

III. Fuel Prices for Power Generation

IV. Hedge Program Impact

V. Spot Market Purchased Power Prices

VI. The Need for Additional Capacity

VII. Planning Requirements for Fuel Adjustment Clause

Q. Are you sponsoring any schedules?

A. Yes. I am sponsoring the following schedules –

- **Schedule HDR-1** Comparison of Capacity Mix
- **Schedule HDR-2** Comparison of Joint and Stand-alone Dispatch
- **Schedule HDR-3** Fuel and Purchased Power Allocation Ratio
- **Schedule HDR-4** 3-Month Average 2007 NYMEX Strip and Weighted Burner Tip Cost of Gas
- **Schedule HDR-5** Impact of Hedge Program
- **Schedule HDR-6** Spot Market Purchased Power Prices
- **Schedule HDR-7** Comparison of Aquila and MIDAS Gas Price Curves
- **Schedule HDR-8** Resource List from April 2005 IRP

EXECUTIVE SUMMARY

Q. Please provide a brief summary of your testimony.

A. In **Section I**, I describe the generation and supply resources of MPS and L&P. On Schedule HDR-1 HC I list the resources used to normalize the 2005 test year energy costs.

In **Section II**, I describe the general method used to normalize the test year energy costs. On Schedule HDR-2 HC, I show the cost difference between jointly dispatching MPS and L&P and dispatching them on a stand-alone base. On Schedule HDR-3 HC, I propose the percentages to allocate the jointly dispatched energy costs to each of MPS and L&P. This allocation percentage is important to the implementation of a fuel adjustment clause.

In **Section III**, I describe the methodology used by Aquila to arrive at a burner tip gas cost of $**____**/mcf. The weighted average burner tip cost of gas and the underlying natural gas commodity cost are shown on Schedule HDR-4 HC. This section also discusses Aquila's approach to delivered coal prices.

Section IV supports the adjustment for Aquila's hedging program. This adjustment reduces revenue requirements by approximately $**__________**. Schedule HDR-5 HC shows Aquila's hedge positions at December 31, 2005 and supports this adjustment. In arriving at this adjustment, it is important to use the same underlying cost of natural gas commodity as is used in the other normalizing adjustments for energy costs.

Section V describes Aquila's approach to normalizing spot purchased power costs. Aquila's approach normalizes purchased power costs for both weather and the underlying fuel costs of production. Schedule HDR-6 HC shows the weighted average cost of purchased power is $**_____**.

Section VI describes Aquila's need for additional capacity. Aquila is pursuing coal-fired base load capacity in the 2010 time frame. Aquila still needs additional peaking/intermediate capacity. In 2005, 84% of Aquila's native load energy requirements were supplied from either base load generating plants or long-term base load purchase power contracts. Aquila needs **___** MW by 2008. Aquila's load is growing at about **__** MW per year.

Section VII describes how Aquila has met certain proposed rules connected with the fuel adjustment clause, including having an integrated resource planning process and considering demand side resources. Certain resource characteristics required are supplied on Schedule HDR-8 HC.

I. MPS AND L&P 2005 OPERATIONS AND RESOURCES

Q. Please describe Aquila Networks – MPS ("MPS") electric utility operations.

A. MPS provides electric service in Western and North Central Missouri. In 2005 it had a non-coincident summer peak load of **____** MW compared to a coincident MPS/Aquila Networks - L&P ("L&P") peak load of **____** MW. The MPS and L&P peaks did not occur in the same hour. Therefore the coincident peak was slightly lower than the two individual peaks. MPS provided capacity and energy with energy generated by its seventeen generating units and purchases under its five power purchase contracts as well as purchases from short-term and spot market sources.

Q. Please describe the MPS generating resources.

A. The MPS generation resources consist of three coal-fired steam units at the Sibley Generation Station ("Sibley"), an eight percent share in each of the three coal-fired steam units at the Jeffrey Energy Center ("JEC"), three gas-fired combustion turbines at the South Harper Peaking Facility, ("South Harper"), four gas/#2 fuel oil-fired combustion turbines at the Greenwood Energy Center ("Greenwood"), two gas-fired jet engines at the TWA Overhaul Base ("KCI"), one gas-fired combustion turbine at the Ralph Green Station, and one oil-fired combustion turbine at the Nevada substation. MPS also receives energy from an ownership share (0.12 MW) of Jeffrey Energy Center wind generation.

Q. Please describe the MPS purchased power contracts.

A. MPS has long-term purchases sourced from Nebraska Public Power District ("NPPD Cooper") and the Gray County Kansas Wind Farm ("Gray County"). NPPD Cooper is a contract for base load power. MPS also had short-term purchased capacity and energy contracts with Sunflower Electric Cooperative ("Sunflower") and had a short-term tolling contract with the Aquila merchant group sourced at Crossroads Mississippi ("Crossroads"). During 2005, the two short-term contracts expired.

Q. Please describe the L&P electric utility operations.

A. L&P provides electric service in North Central and North West Missouri. In 2005 it had a summer peak load of **___** MW. L&P provided capacity and energy with energy generated by its eight generating units and purchases under two power contracts as well as purchases under short-term and spot market sources.

Q. Please describe the L&P generating resources

A. The L&P generation resources consist of an 18% share of the Iatan coal-fired steam unit and various units at its Lake Road Generation Plant comprising one coal-fired steam unit, three coal/natural gas-fired steam units, one natural gas-fired combustion turbine ("CT"), and two oil-fired jet engines.

Q. Please describe the L&P purchased power contracts.

A. L&P has long-term purchases sourced from Nebraska Public Power District ("NPPD Gentleman") and the Gray County Kansas Wind Farm. NPPD Gentleman is a contract for base load power.

Q. Were all of these resources used for normalization of the test period?

A. No. There were changes to the resource mix that were made in consideration of expiring purchased power contracts and adjustments to capabilities based on review and testing of the units. Schedule HDR-1 HC lists the resources used to adjust production and purchased power expenses as compared to the test year.

Q. Please explain the primary differences between the 2005 test year and the resources used in the adjusted test year.

A. The first column on Schedule HDR-1 HC shows the resources modeled and is labeled as "Adjusted Test Year". The second column is the actual resource capacity mix for 2005. The adjusted test year reflects minor adjustments by unit to reflect expected capabilities. The most significant difference, however, is a long-term capacity solution to replace the short-term contracts that expired in 2005 and to add capacity for load growth. The fixed costs related to this capacity solution are described in Aquila witness Kevin Noblet's testimony. Energy costs for this capacity solution have been modeled as a mix of combustion turbines and market purchases. A true-up date has been requested by Aquila witness Susan Braun. The capacity and energy costs related to this capacity solution will be revised at the true-up date.

II. ANNUALIZED MPS & L&P FUEL & PURCHASED POWER EXPENSE

Q. For MPS and L&P what are the amounts and expenses for total fuel and purchases in the test case?

A. The costs of total fuel and purchases are enumerated in the testimony of Aquila witness Susan Braun.

Q. How do those costs relate to the proper amount of fuel and purchased energy expense to be used in setting rates for MPS and L&P?

A. The test year costs are based upon actual expenses that were dependent upon actual operating conditions during the test year. These costs have been adjusted. During the twelve-month period ending December 31, 2005, operating conditions occurred that resulted in several cost items being either too high or too low to properly represent normal expenses for a rate case test period. These include, for example, the resources mix adjustments shown in Schedule HDR–1 HC and adjustments in fuel and purchased power prices to reflect current markets. Because of abnormal conditions, it is necessary to adjust high and low expenses to develop an appropriate annualized fuel and purchased energy expense for the test period.

Q. What method for annualizing the test year fuel and purchased power expense do you recommend for purposes of this case?

A. The proper method for annualizing the test year fuel and purchased power expense is to normalize and annualize unit sales, system requirements, system peak demand, generating unit maintenance and forced outages, the availability and price of purchased power and energy, and the price paid for fuel. After doing this, the fuel and purchased energy should be dispatched by a reliable and accurate production cost computer model to develop the appropriate generation and purchased energy levels and the resulting amount of fuel burned. Aquila uses the RealTime computer software for its production cost model.

Q. What does RealTime do?

A. RealTime is a software package. This package has historically also been used by Staff. RealTime performs an hour by hour simulation of Aquila's generating assets and purchased power resources. The hourly weather-normalized loads (customer usage) are an input to the model. Within the operating limitations identified by Aquila to the model, RealTime will schedule units (supply the customers) in a least cost manner. This process of dispatching the lowest cost generating units before higher cost units is referred to as an economic dispatch.

Q. Are MPS and L&P systems dispatched from the same model?

A. Yes. The two systems are modeled in a joint dispatch. Two additional stand-alone production simulations are performed to demonstrate the cost of separate dispatch for each system.

Q. What was the difference in fuel cost between the joint and separately dispatched models?

A. The difference was a savings from joint dispatch of over $**_________** as reflected on Schedule HDR-2 HC.

Q. Why did you prepare both stand-alone and joint dispatch models?

A. The joint dispatch model reflects the expected cost of our present day operating mode. It is performed to support the total dollar amounts we are submitting to be included in the cost of service. Stand-alone modeling is performed to demonstrate the continued benefits provided by the ability to joint dispatch the MPS and L&P systems as a result of acquisition of L&P by Aquila. In prior cases, the stand-alone models have also been used to allocate the total joint dispatch costs between MPS and L&P.

Q. Were the stand-alone models used to allocate costs in this case?

A. No. We have observed that using the average annual costs in the stand-alone models to allocate costs for ratemaking does not accurately reflect the way actual joint dispatch costs are incurred and allocated on our books on an hourly basis.

Q. Why is it important that the allocation used reflect the way actual costs are incurred and allocated on Aquila's books?

A. If rates are designed differently from the way costs are recorded, it is possible for the actual cost recovery to be different from the way it is intended, particularly if rates contain a fuel adjustment clause.

Q. How have the costs been allocated in this case?

A. A ratio was calculated from the actual 2005 on-system fuel and purchased power costs recorded on our books. This ratio was compared to the similarly computed ratios of the previous four years. It was noted that the ratio has remained highly consistent despite changes in weather and resources. The allocation ratio is shown on Schedule HDR-3 HC.

Q. Did Aquila develop its recommended annualized test period fuel and purchased energy expenses for this case using the method you just described?

A. Yes.

Q. During the test period, what expense items, if any, were adjusted as a result of annualizing fuel and purchased energy expense?

A. Adjustments were made to:

<u>System requirements.</u> Adjustments were made to peak load and energy to reflect normalized weather. System requirements are developed from load profiles and excess energy calculations. The weather normalized load adjustments are sponsored by Aquila witness Robert Adkins and are found in his direct testimony.

<u>Fuel Costs.</u> Adjustments were made to reflect a normalized fuel market. Fuel cost adjustments are discussed in the next section of my testimony.

Purchased Power Costs. Adjustments were made to reflect a normalized purchased power market. Purchased power cost adjustments are discussed in a following section of my testimony.

III. FUEL PRICES FOR POWER GENERATION

Natural Gas Pricing for Generation

Q. As you discuss gas prices, what will be the basis for discussion?

A. The final average gas price described in this section will refer to the weighted average cost of gas at the burner tip as reflected in the dispatch model. This is the commodity cost of gas adjusted for basis and transportation costs appropriate for each plant, weighted by the amount of gas burned at each plant as dispatched in the dispatch model. The cost of the natural gas commodity is the largest component of the burner tip cost. The commodity cost component of the burner tip cost is based on the New York Mercantile Exchange ("NYMEX") commodity prices at the Henry Hub. This is the most widely used index in the gas industry. The NYMEX price does not include basis or transportation costs which must be added to the commodity to determine the actual cost at the plant ("burner tip"). Basis, which can be thought of as the price difference between two locations, can be either positive or negative. Recently, basis to our region has been negative, so of course, adding a negative basis is the same as subtracting.

Q. What method of market price determination does Aquila propose for this case?

A. In the previous case, Aquila proposed burner-tip prices that were derived from a natural gas price curved based upon an average of NYMEX natural gas futures prices. Aquila again proposes this method. The company has calculated a 90-day average of the NYMEX futures market price for each individual month of the 2007 calendar year. The average was calculated using the prices that occurred on each day in the first three months of 2006. If there is a true up date, we will recalculate the 90-day average as of that date.

Q. Please describe in greater detail.

A. For example, every day until June 2007, the market determines a market price for the delivery of natural gas in the month of June 2007. This market price is based on futures contracts executed between buyers and sellers. The market price for gas to be delivered in June 2007 can fluctuate every day. In order to eliminate the bias that might occur from picking a single day's price, while still reflecting prices that are reasonably current, we have averaged the daily prices that occurred over a three month period. In order to eliminate the bias that might occur from picking prices from a single day or a using a spot price and applying it to the whole year, we calculated the averages for each month of 2007. These prices are known and represent average prices for actual market transactions for natural gas.

Q. What is a natural gas futures contract?

A. A futures contract is an exchange tradable contract that obligates each party to buy or sell a specific amount of a commodity (natural gas) at a specified price for delivery in a specified month, delivered at a specified delivery point.

Q. What is a spot price?

A. In its most general form, "spot price" simply means the current price of any commodity or contract. More narrowly, it can refer to either the day ahead price of natural gas or the first of month index price. The day ahead price is the price today for gas delivered tomorrow. The first of month index price is the price for equal amounts of gas to be delivered each day of the current month. When comparing futures contract prices to spot prices, spot price is generally referring to the first of month index price. The first of month index price refers to the average price during the last week of month for equal daily delivery of natural gas during the following month. The index price is typically tied to a specific natural gas pipeline.

Q. How does the price of a futures contract differ from the price of a spot market contract?

A. The price of spot natural gas is the price you can buy natural gas for at the beginning of the month and have it delivered this month. The price of a futures contract is the price you can buy natural gas for today and have it delivered in a specified month in the future.

Q. Is the price of a futures contract a prediction of the spot price in the future?

A. The price of a futures contact should not be confused with the spot price of natural gas in the future. The price of a futures contract is the **actual** price of gas today for gas to be **delivered in the future**. Through the futures contract price, we can know what the price today is of gas delivered in the future. We cannot know today what the spot price on that future date will be. The spot price on that future date will reflect the actual impact of weather, wars, hurricanes, production costs, delivery costs, supply, and demand on natural gas on that date. These factors will certainly be different than the expectations of today.

Q. Can a futures contract actually be used to buy natural gas for future delivery?

A. Yes. A futures contract is a contract for physical delivery of natural gas.

Q. Must physical delivery be taken of the natural gas under a futures contract?

A. No. The contract can also be settled financially by liquidating (selling) the position at any time before the settlement date. In fact such contracts are frequently settled financially, not physically.

Q. Can a spot contract actually be used to buy natural gas for future delivery?

A. No. At spot contract at today's prices would require delivery this month. By itself, a spot contract cannot be used for future delivery. It might be theoretically possible to couple a spot contract with a contract for gas storage. The storage costs would be relatively costly. However, in reality, you could not buy all of your gas needs for next year on today's spot market and store it until next year. The physical, contractual, and operating limits of natural gas storage facilities would prevent this from actually occurring.

Q. Is the purchase of a futures contract the only way to "lock in" the futures price?

A. No. There are a number of other contracts whose prices are determined by the futures price. These other contracts include swaps, calls, and puts. These contracts provide additional ways to, both lock in the futures contract price or hedge the price of natural gas.

Q. Does Aquila use swaps, calls, and puts to hedge the price of natural gas?

A. Yes. The testimony of Aquila witness Gary Gottsch describes are hedging program in greater detail.

Q. Is it appropriate to use the current NYMEX futures contract prices for normalizing the fuel and purchased power costs in this rate case?

A. Yes. Aquila has entered into contracts that are based on the futures contract prices. As described in Gary Gottsch's testimony, Aquila's program is designed to hedge two-thirds of our gas generation and on-peak purchased power. Therefore the actual cost of our future natural gas commodity used is tied to the NYMEX futures contract prices.

Q. How are the average commodity prices calculated by Aquila utilized?

A. In order to ensure consistency among the various normalizing adjustments, these commodity prices are used in several places. First they are used as a major component of the cost of fuel burned in the gas-fired generators dispatched by the dispatch model. Second, these same prices are used to reflect the impact of the Company's hedging program. Third, these same prices are used as a major component in the cost of fuel used in the determination of the market price of purchased power from gas-fired generators. Electric utilities purchase power at a price derived from the cost of producing the power.

Q. What does Aquila propose as the price of natural gas?

A. Attached is Schedule HDR-4 HC. This schedule shows both the commodity component of burner tip gas, calculated as described above, and the monthly and annual weighted average burner tip cost of gas from the dispatch model.

Q. Are there any independent studies, publicly available, that support Aquila's natural gas prices?

A. Yes. Although gas prices have dropped some since Aquila prepared its gas price outlook for this case, the Department of Energy's Energy Information Administration reported in its May 2006 Short-Term Energy Outlook that the current market conditions indicate a $9.17/mcf average Henry Hub price for 2007.

Q. What is Aquila's weighted average burner tip cost of gas from the dispatch model?

A. $**____**/mcf.

Coal Prices for Generation

Q. How were coal prices for the test year determined?

A. Coal prices for generation are taken from existing contracts, as are the coal transportation costs. The prices used are the prices required by the contracts as of June 30, 2006.

Q. What has been the trend in coal prices?

A. In general, coal prices under new contracts have been rising. The Department of Energy's Energy Information Administration reports that, in the electric power sector, current market conditions indicate average coal prices will be 7.8% higher in 2007 than in 2005. From 2004 to 2007 the indicated increase is 23%. Underlying causes include increased demand for low sulfur coals, rising diesel fuel costs for transportation, and depletion of several high-btu low-sulfur coal mines.

Q. Were any adjustments made for terminated contracts?

A. No. The Co-op coal contract was terminated by Co-op during 2005 due to operational problems. The initial term of this contract extended until the end of 2006. Replacement coal has been acquired. The coal prices used represent the prudently incurred known and measurable prices in the existing contracts.

Q. How was the decision made to choose Co-op as a supplier?

A. In 2003 Aquila issued a Request for Proposal ("RFP") for coal. Five companies responded to the 2003 coal RFP. Three of the responders were judged unable to meet our coal supply needs due to existing or expected operational problems. One of these three was not operating at the time and declined to bid. One could supply less than half the coal Aquila requested in the RFP. One proposed a mine that was unlikely to meet our needs beyond 2004. This third supplier's mine, in fact, discontinued production in late 2004. That left two potential suppliers. Both were evaluated to have coals with similar costs. However, one of the two coals was judged to have undesirable operating characteristics in our plants because of the chemical makeup of the coal. The other supplier was judged to have greater risks because it is a relatively small mine. We therefore concluded that the possible risks associated with a smaller supplier were preferable to the known risks of burning undesirable coal.

IV. IMPACT OF HEDGING PROGRAM

Q. What is the purpose of the hedging program?

A. The purpose of the hedging program is to reduce the impact of gas and purchased power price volatility. Reducing volatility does not necessarily mean reducing cost. When prices are rising the hedge program will reduce costs by producing offsetting gains. When prices are falling, the hedge program will produce offsetting costs. The hedge program is described in greater detail by Aquila witness Gary Gottsch.

Q. How is the impact of the hedge program determined?

A. By comparing the hedge contract prices to the current cost of the underlying commodity the current value of the hedge program can be determined. When prices are higher, the hedge program will produce offsetting gains. When prices are lower, the hedge program will produce offsetting costs. In this way the volatility from price fluctuations can be partially mitigated.

Q. What is the hedge program impact reflected in this case?

A. Schedule HDR-5 HC shows the impact of the hedging program using the same commodity prices as used for native generation. For each month of 2007, the hedges were valued against the current commodity price for that month. If a different view of the current price were determined, the hedges would have a different value. To be consistent and accurately reflect the impact of hedging, the same prices must be used 1) to value the hedges; 2) to price for fuel used for generation in the dispatch model; and 3) to price the fuel underlying purchased power generation. Electric utilities purchase power at a price derived from the cost of producing the power.

V. SPOT MARKET PURCHASED POWER PRICES

Q. In developing the annualized purchased energy expense in this case, did Aquila adjust the price paid for spot-market energy from what was actually paid during the test year?

A. Yes, an adjustment was made to normalize hourly purchased power prices and reflect current fuel prices and economic conditions.

Q. What was the result of normalizing the hourly purchased power prices?

A. Schedule HDR-6 HC shows the weighted average monthly and annual purchased power prices as dispatched from the dispatch model using the hourly prices developed with the MIDAS software.

Q. What are the drivers of spot purchased power prices?

A. Electric utilities purchase power at a price derived from the cost of producing the power. The key drivers of the price for power are: existing and proposed generation, current load profiles and load growth, transmission constraints, and the current level of fuel costs with fuel price movements. Technological advancements to the production of power can have an impact over time, but have a minimal impact in the test year power price estimates. Therefore those advances are left out of the price determination model.

Q. Please describe the method used to develop the power market price estimates.

A. Aquila used the Global Energy Decisions ("GED") MIDAS Gold ™ analysis package ("MIDAS"). The analysis package includes functionality and power plant operating parameters for developing spot market purchased power prices for market regions. Aquila used this functionality to develop market prices for the region in which it operates, specifically the Southwest Power Pool ("SPP"), Northern Subregion ("SPPN").

Q. How does MIDAS develop these prices?

A. MIDAS utilizes a national database of power production from GED that is specially formatted for use in MIDAS. MIDAS has as its source the current GED Energy Velocity ™ database.

The MIDAS Gold ™ database contains unit specific operating data on every operating plant within NERC. These operating data include unit capacity, heat rate, fuel type, variable O&M costs, fixed plant costs, etc. GED compiles these data from published resources such as FERC Form 1 submissions and quarterly CEMS data compiled by the EPA.

Regional loads are included in the MIDAS Gold ™ dataset. Regional loads and 10-year expected loads are reported by NERC region in the EIA-411. GED collects this information and breaks down present load and growth by market area. The MIDAS Gold ™ data set uses this information to simulate the load growth of all regions and market areas in NERC. For the test year, neighboring systems load profiles were modeled from the information for each neighboring utility and region submitted to NERC.

The MIDAS Gold ™ software can be used in a variety of ways. When used for price modeling, the model is being used in the "multi-area" mode. The multi-area mode of analysis is basically an application of a transportation linear programming model. All regions of the country are condensed into market areas, each with a load profile and a set of generation resources. Within each market area, loads and resources are matched 8760 hourly periods per year.

The market areas are connected in the model by a series of transmission lines, each subject to a transmission constraint. Price differences in market areas connected with an unconstrained transmission path will cause the model to assume a power flow between the two areas, the effect of which will be to lower the cost in the high price area and increase the cost in the low cost area. This assumed power flow increases until the two market prices have equilibrated at an identical level or the transmission line has reached its limit. Market prices are simultaneously determined for all regions within the model study.

Q. Is MIDAS similar to RealTime dispatch model used by Staff and Aquila to normalize production costs?

A. Yes, in a number of ways. Both are models that can perform economic dispatch calculations for power plants. Both models use normalized loads to normalize production costs for weather, adjust for load changes, and adjust for changes in fuel costs. They differ in several important ways. Realtime comes "empty". Aquila must input and describe each of Aquila's generating units, system loads, fuel costs and operating parameters in order to model production costs. It is very good and very flexible in this regard. MIDAS, in contrast, comes "full". It is pre-populated with every power plant in NERC already set up with operating parameters, loads for each Company and region, transmission line capacities, and fuel costs. RealTime can do an economic dispatch for a Company. MIDAS can perform an economic dispatch for a market region, or even the nation. RealTime, by performing an economic dispatch of a company's resources, can determine the production cost to supply the next MWh of load. MIDAS, by performing the economic dispatch for a market region, can determine the production cost to supply the next MWh of purchased power.

Q. Does GED test the spot market price model used by MIDAS?

A. Yes. GED has communicated to us that it periodically performs a "back cast" to test its spot market price model. To do this, the actual historical reported loads and the actual historical spot energy prices are used to project the spot market purchased power prices. The projected prices are compared to the actual spot purchased power prices. GED uses this process to continually calibrate its model to actual market conditions and refine its modeling accuracy.

Q. Does Aquila modify the MIDAS dataset?

A. Aquila may adjust for current fuel costs assumptions, however, Aquila does not modify any other pre-supplied information in the production of the spot market price curve for power.

Q. Please explain which fuel costs are used in power price determination.

A. The power market price estimating methods used by Aquila are concerned with only a few types of primary energy source costs. Nuclear fuel, coal, hydro, natural gas and fuel oil are the fuels that have a material impact on the ultimate market price for power.

Q. Please describe the method of updating primary fuel source prices.

A. Fuel costs assumptions vary by the fuel being considered. The methods used for determining the cost of each primary energy source are considered separately.

Q. Describe the method used to model nuclear, coal, and hydro fuel costs.

A. The majority of the energy produced in the country is generated by base loaded plants most of which use nuclear, coal, or hydro fuels (stable cost) as their primary energy source. The costs of these sources have two features in common. First, the cost is heavily dependent upon the individual plant. The costs for fuel at these plants vary due to a large number of factors, including refueling schedules, coal and delivery contracts, and water usage constraints. The second feature these fuel costs have in common is that, compared to natural gas, they are relatively stable and do not generally exhibit high levels of volatility. Therefore, the fuel cost estimate for actual fuel purchased costs contained in GED's Energy Velocity™ database for each individual plant is likely to hold throughout the timeframe of the test year. Therefore, for test year adjustment purposes, Aquila did not modify GED's costs for these fuels.

Q. Have coal and coal transportation costs changed over the past several years?

A. Yes. As noted above the Department of Energy's Energy Information Administration reports that, in the electric power sector, current market conditions indicate that average coal prices will be 7.8% higher in 2007 than in 2005, with the bulk of this increase occurring in 2006. From 2004 to 2007 the expected increase is 23%. Electric utilities purchase power at a price derived from the cost of producing the power. The underlying cost of coal is one cost of producing the power.

Q. Please explain how natural gas prices are adjusted for current market conditions.

A. Natural gas is a significant cost component for power produced from natural gas-fired generating units. Natural gas prices are highly volatile. In recent experience and on multiple occasions, natural gas prices have increased by double or triple and also dropped by half or more. Unlike nuclear, coal, or hydro plants, the cost of producing power from natural gas-fired plants cannot be characterized as slowly rising or steady. Due to the volatile nature of the price of natural gas and the increasing percentage of time that natural gas-fired generating units are the marginal price unit, purchased power prices must be adjusted to reflect the current price expectation for natural gas.

The current price expectation for natural gas prices was developed using the method described in my testimony above. Essentially an average of the natural gas futures over a three month period was developed.

Q. Is natural gas the only driver of spot purchased power prices?

A. No. However, it certainly is one of the most volatile. As noted above, purchased power prices are impacted by more than just natural gas prices. Purchased power can be priced from base load units or from peaking (including intermediate) load units. Peaking units are predominately gas fired and are heavily influenced by the price of gas. Base load power prices are not generally gas-fired and those prices move somewhat differently. However, there is a natural tendency, even if supported only anecdotally, for all the fossil fuels to move together, either as a result of fuel substitution, competitive/opportunistic pricing, or increased production and transportation costs. For example, the cost of delivered coal has increased as a result of higher diesel costs for rail transportation.

Q. How are fuel oil prices estimated?

A. Fuel oil appears to drive power prices for certain months of the years in certain areas of the country, primarily Florida and the Northeast. In general, the impact of fuel oil price movements to the power market prices in the Midwest is insignificant. However, fuel oil prices should not be ignored if natural gas prices are modified. An appropriate price relationship between natural gas and fuel oil should be maintained. For purposes of modeling current purchased power prices, we reviewed the fuel oil data in the MIDAS model. We determined that the MIDAS fuel oil data did not require adjustment. Therefore we left the fuel oil data unchanged.

Q. Does MIDAS include a current market price curve for natural gas prices?

A. Yes.

Q. Why did Aquila not use that price curve?

A. The MIDAS dataset is not frequently updated. The MIDAS price curve may be appropriate at the time the dataset is published. The price curve in MIDAS may not represent either the current price expectation or the price expectation that may exist at a true-up date. Therefore, Aquila developed a method for establishing the current market prices that can be updated as needed.

Q. How does the price curve provided by GED and included in the MIDAS dataset compare to Aquila's price curve?

A. A comparison of the two price curves is shown on Schedule HDR-7 HC. As can be seen, at the time Aquila prepared its gas prices, Aquila's method produced a curve shaped very much like the curve included in the MIDAS dataset. This gives us confidence in our methodology for updating the gas price.

Q. What was the highest level of power purchased in the 2005?

A. In 2005, the highest level of spot purchased power actually acquired in any single hour was 869 MW.

Q. What level of purchased power did Aquila make available in its dispatch model?

A. The level of available purchased power varies by month. In the summer months we modeled 900-950 MW. In the other months we modeled 1200 MW.

Q. What happens if the level of available purchased power is set too high?

A. This will lower the overall revenue requirements. The model dispatches on an economic basis. In general, it dispatches the lowest cost resources first and the highest cost resources last. If too much purchased power availability is modeled, in those times when purchased power is lower cost than generation, too much of the lower cost purchased power will be dispatched.

Q. Is this level of purchased power reasonable?

A. Yes. It is reasonable given the actual level experienced in 2005 and based on discussions with our wholesale managers.

VI. THE NEED FOR ADDITIONAL CAPACITY

Q. Why does Aquila need additional capacity?

A. Beginning in the summer 2005, Aquila needed capacity in order to replace an expiring purchased power contract and to meet additional load growth. The expiring purchased power contract was for 500 MW. Aquila replaced 390 MW through a combination of constructing a combustion turbine power plant and entering into a long term base load contract. In 2007, Aquila needs approximately **___** MW of capacity. Aquila's load, plus capacity reserves, grows approximately **__** MW per year. Although our wind contracts do not change in 2008, the accredited capacity of our wind energy contracts changes from **__** MW to **_** MW under current Southwest Power Pool capacity standards. Therefore our total capacity need in 2008 is expected to be approximately **___** MW. Aquila is currently meeting its capacity needs through short-term contracts.

Q. How does Aquila determine how to address its capacity needs in the long term?

A. Aquila utilizes the principles of least cost utility planning. Least cost utility planning is an economic analysis method with the lowest total system operating cost as the objective target. Least cost utility planning methods are applied to an Integrated Resource Plan ("IRP"). The IRP is the result of testing available and hypothetical resource candidates under various scenarios and determining which of those candidates most economically meets the needs of the system.

Q. Did the IRP consider a mix of coal and gas-fired resources?

A. Yes. A need for coal-fired generation in the 2010 time frame was identified. Aquila is participating in the Iatan II coal plant.

Q. Why is coal not used to meet all of Aquila's capacity needs?

A. While coal-fired power plants have a low fuel cost per megawatt hour of electricity produced, they have a very high cost of construction. The total cost of these plants to the customer is lowest when the high cost of construction can be spread over a large number of megawatt hours of electricity. This requires the plants to be able to operate a very high percentage of the time to cost effectively serve native load customers.

Q. How much of Aquila's load is served by base load plants?

A. In 2005, 84% of Aquila's native load energy requirements were supplied from either base load generating plants or long-term base load purchase power contracts.

Q. How would you describe the 16% not served by base load?

A. This portion is not a steady load. It occurs in a relatively small percentage of the hours of the year. This portion is best served by intermediate load generation or peaking generation.

Q. How did Aquila determine the available candidates for meeting the resource needs?

A. Aquila develops available candidates from three methods. The first method was the use of an RFP. An RFP is a formal request sent to prospective suppliers asking them to submit competitive bids to supply the resource. The second method was a process called "canvassing" where Aquila used informal contacts with other utilities at the management, operations, and planning levels to promote dialog over supplying bids or solving mutual resource goals together. The third method was to develop in-house estimates for self-build resource projects. Each of these methods produced candidates for consideration.

Q. What was the result of this process?

A. One of the respondents to our RFP indicated they may have a 600MW combined cycle plant available. This power block, though larger than the immediate need of our system, represents a unique opportunity and a capacity solution that we feel obligated to evaluate. Our initial evaluation indicated the opportunity might be available at a price that would make it beneficial to Aquila's customers. In simple terms, the cost today of this large block may be less expensive than the cost of two or more smaller blocks installed over a number of years.

Q. How is this capacity solution included in this rate case?

A. This capacity solution has been included in the case at a value addressed by Aquila witness Kevin Noblet. This opportunity remains under evaluation. A true-up date has been requested by Aquila witness Susan Braun. If we decide to pursue this capacity solution, we expect to have a definitive value by the true-up date. The capacity and energy costs will be adjusted accordingly.

VII. PLANNING REQUIREMENTS FOR FUEL ADJUSTMENT CLAUSE

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

A. The purpose is to describe how Aquila has complied with certain requirements of the Commission's rules regarding a fuel adjustment clause.

Q. Does Aquila comply with draft rule 4 CSR 240-3.161(2)(P)?

A. Yes. Aquila has a proposed schedule for heat rate and/or efficiency testing with written procedures. The scheduling and testing of the heat rates of each unit will be in accordance with the Southwest Power Pool criteria (Section 12.1- Electrical Facility Ratings). A 100% capability test is performed once every three years. A 90% operational test is performed in each of the following two years on each unit. These tests are conducted during the months of June through September. The unit's heat rate will be determined with data collected during the Electrical Facility Ratings following the SPP procedures.

Q. Does Aquila comply with draft rule 4 CSR 240-3.161(2)(Q)?

A. Yes. Aquila has an integrated resource planning process (IRP). An objective of this planning process is to identify the least cost and preferred resource plans while maintaining adequate capacity reserves for reliability.

Q. Does Aquila comply with draft rule 4 CSR 240-3.161(2)(O)?

A. Yes. Aquila's IRP considered demand side resources as well as supply side resources.

Q. Why are the resources in the IRP appropriate for dispatch?

A. As stated above, one objective of the planning process is to identify the least cost resources. These resources are dispatched in the IRP on an economic basis. This means the least cost resources are dispatched before higher cost resources.

Q. When was Aquila's last IRP prepared?

A. Aquila prepared its last IRP report in April 2005.

Q. When will the next IRP be prepared?

A. Aquila is in the process of preparing its next IRP, scheduled for completion in February 2007.

Q. Did the April 2005 IRP consider both demand side and supply side resources?

A. Yes. An outside consultant was engaged to recommend demand side resource programs. These resources were grouped into bundles based on cost/benefit characteristics. The April 2005 IRP recommended pursuing the bundles in cost groups A and B. These were considered in the IRP plan.

Q. What planning horizon was used in the April 2005 IRP?

A. The April 2005 IRP evaluated resources over a 20 year horizon.

Q. How do the IRP resources differ from the dispatch model resources?

A. Although both the IRP and the dispatch model used for the rate case are production cost models, they differ in their purposes. The IRP model is based on the MIDAS Gold software. Aquila uses MIDAS for its long range planning. The dispatch model used for the rate case uses the RealTime model. This is also the model historically used by Staff. Aquila uses the RealTime model for short-term planning such as rate cases and budgeting. The resources used in RealTime typically reflect currently existing supply side resources. Occasionally placeholder supply side resources are also modeled. Aquila uses MIDAS to model long-term generic or candidate resources including demand side resources.

Q. What are the expected supply side and demand side resource characteristics for years 2007-2011 shown in the April 2005 IRP?

A. The April 2005 IRP identified the resources and characteristics shown on Schedule HDR-8 HC.

Q. Do the demand side and supply side resources identified in the IRP remain static over time?

A. No. As implementation schedules change, new candidate resources are identified, and as other conditions change, Aquila may evaluate these changes and deviate from the published IRP plan.

Q. Did Aquila consult with anyone during the process of least cost planning?

A. Yes. Aquila met with Staff and representatives of the OPC on numerous occasions to discuss Aquila's progress during the planning process. These meetings were designed to keep these representatives informed and to provide valuable feedback to Aquila about the representatives concerns.

Q. Does this conclude your testimony?

A. Yes

Comparison of Capacity Mix

Entire Schedule HC

Schedule HDR-1-NP

Comparison of Joint and Stand-Alone Dispatch

Entire Schedule HC

Schedule HDR-2-NP

Fuel and Purchased Power Allocation Ratio

Entire Schedule HC

Schedule HDR-3-NP

Cost of Gas

Entire Schedule HC

Schedule HDR-4-NP

Impact of Hedge Program
As of December 31, 2005
Hedges for 2007

Entire Schedule HC

Schedule HDR-5-NP

Spot Market Purchased Power Prices

Entire Schedule HC

Schedule HDR-6-NP

Comparison of Aquila and MIDAS Natural Gas Price Curves

Entire Schedule HC

Schedule HDR-7-NP

Resource List from April 2005 IRP

Entire Schedule HC

Schedule HDR-8-NP

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the matter of Aquila, Inc. d/b/a Aquila Networks-MPS and Aquila Networks-L&P, for authority to file tariffs increasing electric rates for the service provided to customers in the Aquila Networks-MPS and Aquila Networks-L&P area	))))))	Case No. ER-________

County of Jackson)
) ss
State of Missouri)

AFFIDAVIT OF H. DAVIS ROONEY

H. Davis Rooney, being first duly sworn, deposes and says that he is the witness who sponsors the accompanying testimony entitled "Direct Testimony of H. Davis Rooney;" that said testimony was prepared by him and under his direction and supervision; that if inquiries were made as to the facts in said testimony and schedules, he would respond as therein set forth; and that the aforesaid testimony and schedules are true and correct to the best of his knowledge, information, and belief.

H. Davis Rooney
H. Davis Rooney

Subscribed and sworn to before me this 3rd day of July, 2006.

Terry D. Lutes
Notary Public
Terry D. Lutes

My Commission expires:

8-20-2008

Notary Public Notary Seal State of Missouri

TERRY D. LUTES
Jackson County
My Commission Expires
August 20, 2008