

DEC 07 2005

EXECUTIVE SUMMARY
DIRECT TESTIMONY OF DAVID L. STOWE
DOCKET NO. EO-2002-384

Missouri Public
Service Commission

Every meaningful rate design begins with a class cost-of-service ("COS") study. This is because the purpose of the COS study is to distribute a utility's total cost of providing service to its customers. When performed properly a COS will show the revenue that must be recovered from each customer class.

In his testimony, Aquila witness David L. Stowe describes the Company's COS studies; explaining the source of input data, the special studies which enhanced the COS, and describing the logic and assumption of both. Stowe concludes his testimony with the recommendation that the Commission endorse Aquila's COS methods and approve the COS results for use in Aquila's rate design.

Cost of Service Inputs

This section explains the source of the revenue and expense account data which were used in the COS studies. The revenue and expense data came from Accounting schedules based on the Settlement Agreement approved by the Commission in Docket No. ER-2004-034.

Customer Classes

The COS customer classes were identified by Aquila's Load Research department based on each class' load shape. The class load data is described in this section.

Effects of adding Line Losses

This section explains why and how the class load data was increased to reflect line losses. The section explains that the line loss values came from a joint project by Aquila's transmission and distribution engineers in 2002. This section contains two summary tables, the first showing how current tariff rates are combined into COS classes and the second showing how those classes are combined into rate groups.

The Test Year

This section describes the test period for Aquila's COS study and explains the supplemental class data that was developed as input to the COS study.

Method of developing a COS study.

This section describes the logic and method of developing a COS study. The section also describes specifics of Aquila's COS. It explains when and where certain allocation factors might be used, and describes which allocation factors *were* used in Aquila's COS studies. The section also demonstrates Aquila's understanding of the techniques and methods of COS studies.

Distribution Study and the Zero Intercept Method.

This portion of testimony is a detailed description of two lengthy studies completed to enhance the COS studies.

The Distribution Study was completed to distinguish primary distribution costs from secondary distribution costs.

Exhibit No. 4
Case No(s) EO-2002-384
Date 11-07-05 Rptr XF

EXECUTIVE SUMMARY
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The Zero Intercept study was completed to identify the customer costs and demand costs of certain distribution components.

Distribution Study Results

This section describes the results of the distribution studies contained in Schedules DLS-1 and DLS-2. Aquila recommends that the Commission endorse the separation of primary distribution costs from secondary distribution costs and the use of the Zero Intercept method to classify certain distribution costs as demand and customer.

COS Study Results:

This section describes the results of the COS studies contained in Schedules DLS-3 through DLS-10. Aquila recommends the Commission endorse Aquila's COS studies.

Billing Units:

This final section describes the calculation of billing determinants for use in the proposed rate structure. Adjustment factors provided by Staff witness Janice Pyatte were used to develop billing units that best produce the revenues by class from the previous rate case.

Exhibit No.:

Issues: Cost-of-Service,
Distribution Study,
Billing Units

Witness: David L. Stowe

Sponsoring Party: Aquila Networks – L&P
Aquila Networks – MPS

Case No.: EO-2002-384

Before the Public Service Commission
Of the State of Missouri

Direct Testimony

Of

David L. Stowe

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**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI
DIRECT TESTIMONY OF DAVID STOWE
ON BEHALF OF AQUILA INC.
DOCKET NO. ER-2002-384**

1 Q. Please state your name and business address.

2 A. My name is David Stowe and my business address is 10700 East 350 Highway,
3 Kansas City, Missouri.

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

5 A. I am employed by Aquila, Inc. ("Aquila") in the Regulatory Services group as a
6 Senior Regulatory Analyst.

7 Q. What are your duties and responsibilities at Aquila?

8 A. I am responsible for the analysis and preparation of cost-of-service ("COS")
9 studies, cost allocation studies, and rate design. I also prepare analyses, work
10 papers and other supporting documents for various filings with regulatory
11 agencies and reports, both internal and external.

12 Q. Please describe your educational and professional background.

13 A. I am a graduate of Kansas State University with a B.S. in Electrical and
14 Computer Engineering. From 1987 to 1993, I was employed by the Kansas
15 Corporation Commission as a Regulatory Engineer. From 1993 through 1995, I
16 was employed by the Missouri Public Service Commission ("Commission") as a
17 Senior Regulatory Engineer. In late 1995, I left the Commission and moved my
18 family to Kansas City, where, while working with the Kansas City Power &
19 Light Company, I completed the requirements for my Professional Engineering

1 license. In January of 2001, I was employed by Aquila as a Senior Regulatory
2 Analyst for Aquila's Regulatory Services Department.

3 Q. What is the purpose of your testimony?

4 A. I will present testimony explaining the methods used in preparing the COS
5 studies of Aquila Networks – MPS's and Aquila Networks - L&P's ("MPS"
6 and "L&P") electrical systems. I will describe the distribution studies which I
7 performed on MPS and L&P service territories to determine secondary and
8 primary distribution system percentages, and customer and demand category
9 percentages.

10 Q. Are you sponsoring any schedules in this proceeding?

11 A. Yes, I am sponsoring Schedules DLS-1 through DLS-10.

12 Q. Please explain the purpose of these Schedules.

13 A. DLS-1 and DLS-2 show the results of my distribution and zero intercept
14 studies for MPS and L&P. DLS-3 through DLS-10 show the results of the
15 COS studies for MPS and L&P. These schedules show the Income Statement,
16 classification and allocation of rate base and expense accounts, and the
17 calculation of customer, demand, and energy charges that served as a starting
18 point for Aquila's proposed rate schedules

19 Q. What recommendations are you making to the Commission?

20 A. I recommend that the Commission endorse Aquila's COS studies and approve
21 the results for use in Aquila's proposed rate design.

22 **CLASS COST OF SERVICE**

23 Q. Were the COS studies for MPS and L&P performed by you?

1 A. Yes. I worked with Aquila Regulatory Manager Matt Tracy in preparing both
2 studies.

3 Q. What is the purpose of a COS study?

4 A. A class COS study is performed to distribute a utility's total COS among its
5 customers. Customers with similar service requirements and usage
6 characteristics are grouped into classes, and costs are assigned or allocated, as
7 appropriate, to those classes.

8 Q. When are costs assigned and when are they allocated?

9 A. Where a customer class is directly responsible for a cost, the cost is assigned to
10 that class. If the costs are joint or common costs, they must be allocated to the
11 classes based on some allocation factor. The fact that COS studies allocate
12 costs to broad customer classes recognizes the impracticality of assigning costs
13 separately down to individual customers. The goal is to reasonably evaluate
14 the appropriate similar groups of customers for the costs incurred by a utility in
15 providing service to them; it is not to make a precise assignment of costs. The
16 resulting class cost determinations provides revenue targets in establishing
17 customer class rate levels.

18 **COST OF SERVICE INPUTS**

19 Q. Please describe the process used to develop the inputs to the COS studies for
20 MPS and L&P.

21 A. Aquila's Regulatory Services Department held multiple meetings and technical
22 conferences with members of the Commission Staff ("Staff"), members of the
23 Office of the Public Counsel ("OPC") and representatives of the Sedalia

1 Industrial Energy Users' Association ("SIEUA") and the Federal Executive
2 Agencies ("FEA") wherein all of the major cost-of-service issues were
3 discussed. From the discussions in those meetings, and from months of
4 cooperation with the other parties, Aquila's Regulatory Services department
5 developed the data that now serves as the input to the class COS studies I am
6 sponsoring today.

7 Q. What is the source of the financial information you used in performing the
8 class COS studies?

9 A. The cost and revenue information was taken from Accounting Schedules
10 provided by the Staff. These Accounting schedules were derived from a
11 previous Settlement Agreement approved by the Missouri Public Service
12 Commission in Docket No. ER-2004-034.

13 **Customer Classes**

14 Q. What customer classes did you use in your class COS study?

15 A. My COS studies separate fourteen distinct rate classes in MPS's territory and
16 nine distinct rate classes in L&P's territory. The MPS classes are: 1. RES-
17 GEN, 2. RES-SH, 3. SGS-S, 4. SGS-P, 5. LGS-S, 6. LGS-P, 7. LGS-SF, 8.
18 LPS-S, 9. LPS-P, 10. S&C, 11. MUNI-WPR, 12. MODINE, 13. LIGHTS, and
19 14. THERM. The classes used in the L&P class COS study are: 1. RES-GEN,
20 2. RES-H2O, 3. RES-HEAT, 4. SGS, 5. LGS-S, 6. LGS-P, 7. LPS-S, 8. LPS-P,
21 and 9. LIGHTS. In general, these rate classes follow Aquila's tariffs for
22 Residential, Small General Service, Large General Service, Large Power
23 Service, Lights, and Special Contracts. I have created certain sub-classes to

- 1 distinguish residential space heating from general residential, secondary service
2 from primary service, etc.
- 3 Q. How were these rate classes identified?
- 4 A. Aquila's load research group, managed by Matt Tracy, identified the classes
5 based on customer load shapes. Mr. Tracy provided the class load information
6 that included; 1) Monthly and Annual Energy, 2) Monthly Peak Demand, 3)
7 Coincident Peak information, 4) Class non-coincident peak information, 5) the
8 calculation of the A&E-3CP, Average Energy, Class NCP, and Customer NCP
9 allocation factors.
- 10 Q. Were these the same allocation factors that you used in your COS studies?
- 11 A. Yes.
- 12 Q. Did you use allocation factors besides the demand and energy factors mention
13 above?
- 14 A. Yes.
- 15 Q. What other allocation factors did you use?
- 16 A. I used weighted, customer allocation factors to distribute customer related costs
17 to the classes. I also used revenue allocation factors as a technique to assign
18 the adjusted class revenues, from Case No. ER-2004-034, to the classes. The
19 adjusted revenues were separated by tariff rate, but I knew how the tariff rates
20 were related to the COS classes, and was able to calculate the revenue
21 allocation factors.
- 22 Q. How do the COS classes relate to Aquila's current tariff rates?
- 23 A. The relationship is shown in Table 1 below.

Table 1, Customer Classes			
MPS		L&P	
<u>COS Class</u>	<u>Tariff Rate</u>	<u>COS Class</u>	<u>Tariff Ra</u>
RES-GEN; Residential Non-General.	MO860	REG-GEN; Residential Service – General.	MO910, MO911, MO915
RES-SH; Residential – Space Heating	MO870	RES-H20; Residential Service – Water Heating.	MO913, MO914
SGS-S; Small General Service – Secondary.	MO710, MO711	RES-HEAT; Residential Service – Space Heating.	MO920, MO921, MO922
SGS-P; Small General Service – Primary.	MO716, MO745	SGS; Small General Service.	MO930, MO931, MO932, MO933, MO940, MO941
LGS-S; Large General Service – Secondary.	MO720, MO721	LGS-S; Large General Service – Secondary.	MO940 subset
LGS-P; Large General Service: - Primary.	MO25 subset	LGS-P; Large General Service – Primary.	MO940 subset
LGS-SF; Large General Service – Mo. State Fair.	MO25 subset	LPS-S; Large Power Service – Secondary.	MO944 subset
LPS-S; Large Power Service – Secondary.	MO730, MO731	LPS-P; Large Power Service – Primary.	MO944 subset
LPS-P; Large Power Service – Primary.	MO735, MO737	LIGHTS; PAL, Street Lighting and Signals.	All Lighting Rates
S&C; Schools and Churches	MO740		
MUNI-WPR; Muni Water Pumping, Parks & Rec.	MO800, MO810, MO811		
MODINE	MO919		
LIGHTS; PAL, Street Lighting, and Signals.	All Lighting Rates		
THERM; Thermal Energy Storage.	MO650		

- 1 Q. Are these classes the only grouping of rates used in your COS model?
- 2 A. No. Besides combining similar tariff rates into the classes discussed above, I
- 3 also combined rate classes into rate groups.
- 4 Q. What is a rate group?

1 A. A rate group is a technique used by Aquila's COS software to make the
2 distribution of costs to rate classes easier.

3 Q. Please explain.

4 A. Combining rate classes into groups allows the COS software to allocate costs
5 to every class in the group in one step; making the model easier to build,
6 understand, and troubleshoot. In Aquila's COS study, every class of customers
7 that is served at secondary voltage is included in a group called SEC_DIST.
8 Various Federal Energy Regulatory Commission ("FERC") accounts which
9 contain the plant, maintenance, and operational costs for the secondary
10 distribution system, are associated with this group. Primary customers, who do
11 not incur these secondary distribution costs and who are not part of the
12 SEC_DIST group, will not be allocated any of these costs. Direct assignments
13 of costs to classes are also accomplished by using a rate group.
14 These processes can be accomplished without the use of rate groups, but the
15 technique is more complicated and prone to error.

16 Q. What rate groups did you use in the COS studies?

17 A. I used four groups in my COS studies. A group called ALL includes every
18 class in the study. SEC_DIST includes only the secondary customers.
19 PRIM_DIST is a super-set of classes; containing all the classes in SEC_DIST,
20 but also the classes connected to the primary distribution system. Finally, a
21 LIGHTS group was created to directly assign costs to the Lights class. The rate
22 groups, and the customer classes in those groups, are shown in Table 2 below.

Table 2, MPS Group Membership				
	Groups			
Customer Class	ALL	PRIM_DIST	SEC_DIST	Directly Assigned
RES-GEN	X	X	X	
RES-SH	X	X	X	
SGS-S	X	X	X	
SGS-P	X	X		
LGS-S	X	X	X	
LGS-P	X	X		
LGS-SH	X	X		
LPS-S	X	X	X	
LPS-P	X	X		
S&C	X	X	X	
MUNI-WPR	X	X	X	
MODINE	X	X	X	
LIGHTS	X	X		X
L&P Group Membership				
	Groups			
Customer Class	ALL	PRIM_DIST	SEC_DIST	Directly Assigned
RES-GEN	X	X	X	
RES-H2O	X	X	X	
RES-HEAT	X	X	X	
SGS	X	X	X	
LGS-S	X	X	X	
LGS-P	X	X		
LPS-S	X	X	X	
LPS-P	X	X		
LIGHTS	X	X		X

1 **Line Losses**

2 Q. Did you modify the allocation factors prior to using them in your COS studies?

3 A. Yes. I increased each class' monthly energy and demand to account for line
4 losses.

5 Q. What are line losses?

1 A. Line losses are the amount of energy lost during transmission and distribution
2 of electricity, and are primarily due to electrical resistance in the conductors
3 and to inefficiencies within transformers.

4 Q. Why do line losses affect the class energy and demand values?

5 A. When a certain amount of energy is needed at the customer's meter, the utility
6 must generate enough energy to meet that need, plus the line losses. The
7 further the energy travels from the generator, the greater the losses. Thus,
8 secondary customers impose more losses on the system than primary customers
9 because their energy must be carried over more wire and through more
10 transformers. In order to model this in the COS studies, it was necessary to
11 apply a larger loss factor to the secondary customers than the primary
12 customers.

13 Q. Where did the line loss factors come from?

14 A. In 2002, Aquila's transmission and distribution engineers completed a loss
15 study for each of Aquila's service territories. The study used peak and average
16 demand values for the summer and winter of 2001 to derive peak and average
17 loss factors. The final report listed the total peak and average losses for the
18 transmission system, primary substations, primary taps and feeders, line
19 transformers, and secondary lines and services.

20 Using the results of that study, I calculated the peak and average losses to apply
21 to the primary and secondary classes. I applied the peak losses to the class
22 demand, and average losses to the class energy.

23 Q. What effect did the addition of losses have on the allocation factors?

1 A. The addition of losses had no effect on the way the allocation factors were
2 calculated, but they did affect the final allocation factor values. The weighted,
3 demand and energy allocation factors for secondary customers increased
4 slightly when compared to those same allocation factors for primary customers.

5 **The Test Year**

6 Q. What test year did you use for your COS study?

7 A. The historical time period that I used was the twelve month period ending on
8 December 31, 2002, and updated for known and measurable adjustments to
9 September 30, 2003.

10 Q. What class data was developed for the class COS study in this case?

11 A. The class data developed for this case were: 1) hourly demand (KW) data by
12 class, 2) monthly and annual demand (KW) data by class, 3) monthly and
13 annual energy (KWh) data by class, 4) monthly and annual revenue data by
14 class, 5) customer number data by class, and 6) the primary and secondary cost
15 percentages for FERC accounts 364 through 368, 7) and the zero intercept
16 percentage for FERC accounts 364 through 368.

17 **Explanation of the Method**

18 Q. Please describe the method of creating a COS study.

19 A. A COS study involves a three-step process in which rate base investment,
20 operation and maintenance expenses, depreciation expense, and income taxes
21 are assigned or allocated to the customer classes. The first step involves the
22 'functionalization' of costs, the second requires the analyst to classify of the

1 functionalized costs, and the last step entails the assignment or allocation of
2 costs to the customer classes.

3 **Functionalization**

4 Functionalization is possible because the Uniform System of Accounts
5 ("USOA") prescribed by the FERC separates costs according to their
6 functional use. The functions used for *plant* accounts are: intangible,
7 production, transmission, distribution, and general, while the functions used for
8 operating and maintenance *expense* accounts are: production, transmission,
9 distribution, customer accounts, customer service and information, sales, and
10 administrative and general.

11 **Classification**

12 Classification of functionalized costs is performed for the purpose of allocating
13 those costs among the customer classes. Costs are divided into three major
14 classifications: commodity costs, demand costs, and customer costs.

15 Commodity costs are a function of the volume of *energy* (KWh) delivered on
16 the system. An example of commodity costs is the cost of fuel used to generate
17 electricity by a power plant. It is intuitively obvious that more fuel will
18 produce more energy. Thus, fuel costs are classified as commodity costs.

19 Demand costs are a function of the load on, or *power* (KW) delivered to, the
20 electric system. An excellent example of demand costs is found in FERC
21 Account 356: Overhead Transmission Conductors and Devices. Like the
22 example of the fuel costs, it is obvious that the transmission lines, which carry
23 the enormous power from the generating stations to the cities and communities,

1 must be designed and constructed to meet the maximum demand those cities
2 and communities will place on them.

3 Customer costs are those which are a function of the number of customers on
4 the system. An example of customer costs are those found in FERC Account
5 370: Distribution Meters. Since every customer on the system requires their
6 own meter, there is a direct relationship between the number of customers and
7 meter costs.

8 Q. Are there costs that do not fall into one of these three classifications?

9 A. Yes. It is quite common to encounter costs that do not fall neatly into a single
10 category. For example, while the costs in Account 356; "Overhead
11 Transmission Conductors and Devices" are incurred to meet the demand on the
12 conductors, it is equally obvious that the costs to purchase the land or right-of-
13 way for that transmission line (Account 350) are *not*. Neither are they incurred
14 by the energy carried by that line in an hour or month or by the number of
15 customers.

16 Q. How are the costs in Account 350 classified?

17 A. In the case of Account 350, history and tradition play a role in determining how
18 the costs are classified. The National Association of Regulatory Utility
19 Commissions published a manual titled, "Electric Utility Cost Allocation
20 Manual", ("NARUC Manual") that defines the transmission system '... for

1 ratemaking purposes as a group of highly integrated bulk power supply
2 facilities consisting of high voltage power lines and substations.’¹
3 The NARUC manual also indicates that the FERC “defines a transmission
4 system to include: (1) all land, conversion structures, and equipment employed
5 at a primary source of supply... (2) all land, structures, high tension apparatus,
6 and their control and protective equipment between a generating or receiving
7 point and the entrance to a distribution center or wholesale point...”²
8 In light of these definitions by the FERC and NARUC (i.e., wherein land,
9 structures, and conductors, etc. are combined), the costs in all of the
10 transmission accounts have traditionally been classified as demand costs. I
11 would be quick to add, however, that history and tradition are not the only
12 justification for classifying every transmission plant account as demand

13 Q. What other justification is there?

14 A. Much of the cost of transmission system, while not directly related to the
15 number of kilowatts flowing through the lines, can be shown to be indirectly
16 related to that demand.

17 Q. Please explain.

18 A. Consider that the power (KW) flowing though a transmission line is equal to
19 the amount of current flowing though the wires times the voltage. This
20 relationship, in a somewhat simplified form, is shown as:

$$P = V \times I$$

¹ The National Association of Utility Regulatory Commission’s Electric Utility Cost Allocation Manual (Chapter 5, page 69).

1 Where P is the power,
2 V is the voltage,
3 And I is the current.

4 This equation shows that for a given power the equation can be balanced either
5 by increasing the voltage and lowering the current, or by lowering the voltage
6 and increasing the current. Over a century of experience has proven that
7 increasing voltage and lowering current is the most cost effective and efficient
8 way to balance the cost and performance of the transmission system
9 Yet, while higher voltages increase the efficiency of transmitting power over
10 long distances, higher voltages also require greater distances between
11 conductors and other structures such as towers, other conductors, trees,
12 buildings, and the ground to prevent arcing.
13 Higher demand on utility transmission systems has led to higher voltages.
14 Higher transmission voltages, in turn, have led to taller towers, larger
15 insulators, wider cross-arms, wider right-of-ways, etc., and the net result has
16 been an increase in cost for all these components.

17 Q. Is it true that these costs, in much the same way as you describe above, are
18 indirectly related to the *energy* on the system. Couldn't they just as easily be
19 classified as commodity costs?

20 A. In my opinion, no.

21 Q. Why not?

² Ibid.

1 A. The difference between demand and energy needs to be understood. As I have
2 said, power is equal to the voltage times the current. Energy is power delivered
3 over time. Mathematically, energy equals power multiplied by time or ($E = P \times$
4 T). While it can be shown that an increase in power has led to an increase in
5 voltage and thereby an increase in cost; there is simply no analogous way to
6 show that an increase in energy will also lead to an increase in cost. That is to
7 say, moving a certain amount power over the line for three hours does not
8 require taller towers, larger conductors, or more land than moving that same
9 power for two hours. It is unreasonable to classify costs which are incurred to
10 transmit power on the electric system as commodity costs.

11 **Allocation**

12 Q. What is done with the classified costs in the COS study?

13 A. Wherever possible, the commodity, demand, and customer costs are assigned
14 directly to the class which incurred them. However, when a cost cannot be
15 assigned, it is allocated among the classes using an appropriate allocation
16 factor. Weighted allocation factors are generally used to recognize certain cost
17 differentials among classes.

18 Q. What weighted allocation factors did you use in your COS study?

19 A. I used eleven different weighted allocation factors in each COS study. Because
20 commodity costs are based on the volume of energy supplied, all commodity
21 costs were distributed among the classes using *Average Energy* weighted
22 allocators.

1 Demand costs were distributed using one of a number of demand allocators.
2 Transmission demand costs were distributed to the classes using Average and
3 Excess Demand allocators that made use of the systems' three coincident peaks
4 ("A&E-3CP"). Primary distribution demand costs are allocated using the
5 weighted, class, non-coincident peak ("CLASS"). Secondary distribution
6 demand costs are allocated using the weighted, customer non-coincident peak
7 ("NCP") allocators.
8 Customer costs were distributed to the classes using a weighted, customer
9 allocation factor calculated as the number of customers multiplied by the
10 average installed meter cost ("CUST").
11 The demand and customer allocation factors were also calculated for the
12 primary and secondary groups; PRIM_DIST and SEC_DIST. These distinct
13 primary and secondary demand and customer allocation factors were used in
14 the COS studies where appropriate.

15 **DISTRIBUTION STUDY AND THE ZERO INTERCEPT METHOD**

16 **The Distribution Study**

17 Q. If you used one demand allocation factor for primary demand costs and
18 different demand allocation for secondary costs, how were you able to separate
19 the primary and secondary costs?
20 A. I have completed a thorough analysis of MPS and L&P distribution systems for
21 the purpose of identifying and separating the primary and secondary
22 distribution costs, and to determine the zero intercept value for certain
23 accounts. The study included seventeen FERC accounts, but I quickly narrow

1 my focus to the few FERC accounts that shared a primary and secondary
2 distribution function. The result of the study was a set of primary and
3 secondary percentages, and a set of customer and demand percentages for
4 FERC accounts 364 through 368. I used the primary and secondary
5 percentages to separate primary costs from secondary costs, and the customer
6 and demand percentage to classify those separated costs.

7 Q. Which FERC accounts did you analyze as part of your distribution study?

8 A. Table 3 lists the seventeen FERC accounts that were included in the
9 distribution study.

TABLE 3. Cost Allocation Study Accounts	
Account	Description
360001	Elect. Dist. - Land
360002	Electric Distribution: - Land Rights/ROW
361000	Electric Distribution: Substation Structures & Improvements
362000	Electric Distribution: Substation Equip.
364000	Electric Distribution: - Pole/Tower/Fixture
365000	Electric Distribution: - Overhead Conductors
366000	Electric Distribution: - Underground Conduit
367000	Electric Distribution: - Underground Conductors
368001	Electric Distribution: Line Transformer - Other Equip.
368002	Electric Distribution: Line Transformer - Conventional
368003	Electric Distribution: Line Transformer - Pad mount
369001	Electric Distribution: - Overhead Services
369002	Electric Distribution: - Underground Services
370001	Electric Distribution: - Meters Other
370002	Electric Distribution: - Meters PURPA
371000	Electric Distribution: - Installation Cust Premise
373000	Electric Distribution: - Street Lighting

1 Q. Is a complete distribution study necessary to classify the costs shown in the
2 Table 3?

3 A. Not in every case. As I have already stated, certain FERC account costs can be
4 easily classified as commodity, demand, or customer because it is intuitively
5 obvious that the costs are a function of energy, demand, or the number of
6 customers. Therefore, account 371, which contains the cost of installing
7 service to the customer's premises, would be classified as "customer" and
8 would be recovered through a "customer" charge. Similarly, account 362,
9 which contains the cost of substation equipment on the primary distribution
10 system, are not impacted by the number of customers served but by the demand
11 (KW) placed on the equipment by those customers. These costs are
12 appropriately classified as demand.

13 Q. How are costs classified if a distribution study is not available?

14 A. In situations where the necessary data is unavailable or when time will not
15 allow a full distribution study, the analyst may simply classify the costs in
16 FERC accounts 360, 361, 362, 364, 365, 366, and 367 as demand, and the
17 costs in FERC accounts 368, 369, 370 as customer.

18 Q. With regard to all the accounts 360 through 371, did you classify the costs in
19 these accounts this way?

20 A. No.

21 Q. If it is not necessary to analyze the distribution system at all: if you can simply
22 group large numbers of accounts and classify them in bulk, why make the
23 effort to perform such a detailed study?

1 A. Aquila has invested hundreds of millions of dollars to construct and maintain
2 distribution plant in the Missouri service territories. These costs are accounted
3 for in FERC accounts 360 through 372 and are, after the rate-setting process,
4 recovered in Aquila's approved rates. Aquila, like other utilities, is aware of
5 the importance of thoroughly understanding these costs since our revenues are
6 so closely tied to them.

7 Q. As you performed the distribution study, did you encounter anything
8 unexpected or surprising?

9 A. Yes.

10 Q. Please explain.

11 A. In the process of analyzing these distribution systems, I began to realize the
12 need to rethink my preconceived ideas about their design and construction.
13 Many primary and secondary distribution components (Accounts 364 through
14 368), which I had previously assumed to be designed to meet the demand of
15 the customer, were actually designed to meet National Electrical Safety Code
16 ("NESC") requirements. I learned that the NESC sets the minimum
17 requirements of these components many times above the typical customer's
18 demand. I knew that the costs of electrical system components were higher for
19 those capable of withstanding higher demand, and I had expected this to be true
20 throughout my study. But I found was a leveling off of costs as I moved closer
21 to the point of delivery to the customer. It seemed that there is a disconnect
22 between the electrical demand which is placed on the system, and the cost of
23 the system.

1 Q. Please give an example of this 'disconnect'.

2 A. Consider the point on a distribution system where the last length of power line
3 comes to the customer's premises. This segment of cable is referred to as the
4 "service drop" and is accounted for in FERC Account 369. According to the
5 NESC, the minimum size of cable that can be used is a #4 AWG line. The
6 NESC sets this minimum size standard based, not on the capacity, or demand
7 handling capability, of the line, but on safety issues associated with the line;
8 how much ice or wind load the line can handle without breaking.

9 To better see the disconnect I'm describing, consider that the electric industry
10 commonly uses ACSR (Aluminum Conductor with Steel Reinforcing) cable
11 and that the capacity of a #4 ACSR line is about 140 amps. For residential
12 customers this line will operate at about 120 volts. Aquila's distribution
13 engineers estimate that the typical residential customer will draw about 20 to
14 30 amps at this same 120 volts. Thus, the typical residential demand is
15 between one-seventh and one-fifth of the capacity of the smallest conductor we
16 are allowed by the NESC to install.

17 Clearly, the demand on these lines is not the deciding factor when designing
18 them. The NESC requirements are more than adequate to meet the load, and
19 much of the cost for these lines is incurred to meet those requirements rather
20 than the demand.

21 Q. How should the cost for services be recovered in rates?

22 A. The costs for Account 369 are generally classified as customer and are
23 recovered in the monthly customer charge.

1 Q. Please give a specific example of costs that are more appropriately classified as
2 both demand and customer?

3 A. It is appropriately to split the cost of Account 365, Secondary Overhead
4 Conductors, into demand and customer percentages. To illustrate this, I can
5 build off of what I have just explained about Account 369, because the
6 secondary overhead conductors are that portion of the distribution system
7 connecting the service drops to the transformers.

8 Just like the service conductors, the secondary conductors are required by the
9 NESC to be no less than a #4 AWG and operate at the same voltage. The sole
10 difference between the secondary conductor and the service drop is that two or
11 more customers *may* be connected to the secondary system, whereas every
12 customer gets their own service drop.

13 Therefore, the secondary overhead conductors do not have the one-to-one
14 correspondence to the customer that the services have, yet must be sized with
15 capacity far above the expected demand to meet the safety requirements of the
16 NESC. The costs of Account 365 are not a function of customer *or* demand,
17 but of customer *and* demand. It is reasonable, therefore, to classify a
18 percentage of these costs as customer, and the remainder of them as demand.

19 Q. How should the cost of secondary overhead conductors be recovered in rates?

20 A. The portion of the costs which are classified as customer should be recovered
21 in the monthly customer charge. The remainder should be recovered in the
22 demand charge. Where the customer is not charged a demand charge, the
23 demand portion is generally included in the energy charge.

1 Q. Are there other distribution costs that should be classified as both customer and
2 demand?

3 A. Yes. Between the service drops (Account 369) and the primary substation
4 (Account 362) Aquila has installed millions of dollars in equipment that are
5 appropriately classified as both customer and demand.

6 Q. How are you proposing the distribution account costs be recovered?

7 A. The costs in FERC accounts 360 through 362 should be considered demand
8 related and recovered through a demand charge. Likewise, the costs in
9 Accounts 369 through 372 should be classified as customer related and
10 recovered through a customer charge. Finally, the zero intercept method
11 should be used to determine the customer and demand percentages for the costs
12 in FERC accounts 364 through 368 with the customer portion recovered in the
13 customer charge, and the demand portion recovered in the demand or energy
14 charge.

15 **The Zero Intercept Method**

16 Q. What is the Zero Intercept method?

17 A. The zero intercept method refers to a technique or process used to estimate the
18 percentage of the system that is "non-demand" related.

19 Q. Are there techniques, other than the zero intercept method, that will estimate
20 this same percentage?

21 A. Yes.

22 Q. Why did you use the zero intercept method in your COS study?

1 A. I believe the zero intercept method creates a more realistic and accurate COS
2 model and does so by using the most accurate data available. Like many of my
3 colleagues, I aim constantly at improving the COS models I have developed for
4 my company. The zero intercept method is a recognized technique that
5 accurately simulates the real world, and leads to a better COS study. That the
6 zero intercept method is valid and useful is seen in the fact that the NARUC
7 manual devotes considerable attention to it.

8 Q. How does the zero intercept method more realistically reflect the costs of
9 actual distribution systems?

10 A. The zero intercept study that I performed used distribution component data
11 from Aquila's PowerPlant™ Database. This database contains up-do-date
12 property records for every pole, conductor, transformer, insulator, etc. installed
13 in each of Aquila's electric divisions. Using this source of data for the study
14 ensured the analysis would contain accurate, reliable data that describes the
15 actual equipment in the field.

16 Also, the process of calculating the zero intercept required me to interact with
17 Aquila's field engineers and linemen, study the latest construction standards,
18 interview our supply purchasing personnel, and contact equipment vendors.
19 All of this fieldwork was crucial because it allowed me to identify and track the
20 costs from the point of the design and installation of the equipment, to the entry
21 of the job ticket information into the PowerPlant™ Database

22 Q. Please explain the process of calculating the zero intercept.

1 A. In order to calculate the zero intercept cost, I queried millions of records from
2 the PowerPlant™ Database and developed a specialized database which
3 contained current property data. From that data, I determined the cost-per-foot
4 or cost-per-item necessary to install each major distribution component. By the
5 end of the study, I had calculated the "per item" cost for poles of every height
6 and type that Aquila purchases, transformers of every size listed in the current
7 property records, conductors of various diameter and composition, steel and
8 plastic conduit, and installation estimates for trenching and burying
9 underground conductor and conduit, setting poles, stringing wire, and setting
10 transformers.

11 Q. What did you do with the per-foot and per-item costs?

12 A. I charted the per-foot or per-item costs of each component on an Excel graph
13 from which I was able to calculate the zero intercept point.

14 Q. Please explain what you mean.

15 A. Consider the process of calculating the zero intercept point for a component
16 such as conductor. In this example, the actual current property records, for
17 every foot of conductor in the territory, were downloaded into a special
18 database. Then the conductors are separated from all the other components in
19 the database, and further separated by conductor type, diameter, and whether
20 the conductor was insulated or not. The resulting information is then input to
21 an Excel spreadsheet where installation costs are added and the installed price-
22 per-foot of each size and type of conductor is determined and graphed. For
23 instance, the price per foot for #6 AWG wire might be plotted as point W_1 , #4

1 AWG might be point W_2 , #2 AWG is W_3 and so on. This same process was
2 followed for every major component in accounts 364 through 368. On the
3 graph, these data points increase in value (farther from the horizontal axis) as I
4 moved from the origin of the axes toward the right. This means that if I drew a
5 rough line through the data points toward the y-axis, the line would drop
6 toward the origin of the graph. This is precisely the next step in determining
7 the zero intercept. Using linear, exponential, or polynomial regression
8 techniques, a 'best fit' line is extrapolated through the data points and back to
9 the y-axis (the vertical axis) of the graph. The point at which the extrapolated
10 line crosses the y-axis is the y-intercept or the zero intercept value.

11 Q. If you inflated the per-foot or per-item cost prior to charting the costs, would
12 you get an inflated zero intercepts?

13 A. It is possible that you would.

14 Q. What precautions did you take to insure the zero intercept value could not be
15 arbitrarily increased or inflated?

16 A. In the final step of the process, I expressed the zero intercept value as a
17 percentage of replacement cost.

18 Q. Please explain.

19 A. The y-intercept value has the same units (e.g., dollars per foot) as the other data
20 points on the chart. This means that if the data points W_1 , W_2 , and W_3 are
21 inflated because I used replacement costs rather than embedded costs, the
22 intercept value will also be inflated to the same degree. Similarly, if I inflated
23 W_1 , W_2 , and W_3 by a factor of ten, again the zero intercept value would also be

1 inflated by the same factor. In other words, the input (replacement cost) and
2 the output (zero intercept value) are at the same "scale".

3 Here is the critical step that must be understood. The zero intercept cost (zero
4 intercept value) multiplied by the quantity (feet of conductor, for example) is
5 then divided by the total cost (replacement value multiplied by the quantity).
6 The result is a zero intercept *percentage* between 0% and 100%. Due to this
7 last step, inflating or deflating the costs has no net effect on the results. I used
8 the resultant zero intercept percentage to classify the customer and demand
9 portion of Accounts 364 through 368.

10 Q. You have said that you used the Zero Intercept Method as described in the
11 NARUC manual did you follow the procedures in the manual precisely?

12 A. No.

13 Q. Why not?

14 A. The NARUC manual serves as an excellent tool in that it gives a detailed
15 description of a zero intercept study. However, the NARUC manual was
16 developed using data, or assumptions about that data, that was quite different
17 from what I had available. The NARUC manual states that while calculating
18 the zero intercept for account 365: Distribution, Overhead Conductors and
19 Devices, the zero intercept cost should be multiplied by the total number of
20 circuit feet times two. A note explains that the 'circuit feet', not the 'conductor
21 feet' were used to get their customer component. Apparently, the authors of
22 the NARUC manual were working with data wherein the conductor costs were
23 given in dollars-per-circuit-foot. The authors needed to convert this value into

1 the equivalent 'conductor feet', and they did so by multiplying the circuit feet
2 by two. This is a reasonable assumption since every circuit must have at least
3 two conductors to operate: the phase conductor and the ground conductor.
4 The Account 365 data within PowerPlant™, however, was already given in
5 dollars-per-foot of conductor. No conversion was necessary. I deviated from
6 the NARUC manual with respect to other accounts as well, but generally for
7 similar reasons.

8 **DISTRIBUTION AND ZERO INTERCEPT STUDY RESULTS**

9 Q. Please describe the results of your distribution and zero intercept studies.

10 A. These studies are summarized in two tables on the Distribution Study Reports,
11 attached as Schedules DLS-1 and DLS-2. These tables show the total account
12 costs with the primary and secondary percentages, in total dollars as well as in
13 percentages of total account cost. The also show the customer and demand
14 classifications as percentages of total account cost.

15 Q. Why did you allocate a portion of Account 368 (Line Transformers) to the
16 primary distribution system?

17 A. According to FERC's Code of Federal Regulations, Account 368 is used to
18 track the costs of capacitors used for voltage regulation. These devices are
19 used to benefit the entire distribution system and not just the secondary, and
20 should be allocated to the primary system.

21 Q. What impact did your zero intercept study have on the COS study?

22 A. The results of the zero intercept study were used to assign the costs in accounts
23 364 through 368 to the appropriate cost classifications. Once appropriately

1 classified, these costs were distributed to the classes using the proper allocation
2 factors. Therefore, when the results were used in the COS studies, the costs
3 classified as customer were distributed using the weighted, customer allocation
4 factors, and those classified as demand were distributed using weighted,
5 demand allocation factors.

6 **COS STUDY RESULTS**

7 Q. Please describe the results of your class COS study.

8 A. The class COS results for MPS is summarized in the tables of Schedules DLS-
9 3, DLS-4, DLS-5, and DLS-6, and for L&P in the tables of Schedules DLS-7,
10 DLS-8, DLS-9, and DLS-10. Because the schedules for MPS are so similar to
11 the schedules for L&P, I will explain the content of 'pairs' of schedules.
12 Schedules DLS-3 and DLS-7 are the Income Statement reports for MPS and
13 L&P respectively. These schedules show the assignment and allocation of
14 operating revenues, operating expenses, Net Operating Income. The schedules
15 also show a calculation of the shift in revenue into or out of the classes to bring
16 all classes to the return approved by the Commission in Docket No. ER-04-034.
17 Schedules DLS-4 and DLS-8 are Rate Base by Category reports for MPS and
18 L&P respectively. These schedules show by class, the classified cost (i.e., energy,
19 demand, or customer) for each *rate base plant* account.
20 Schedules DLS-5 and DLS-9 are the O&M Expenses by Category reports for
21 MPS and L&P respectively. These schedules show by class, the classified cost
22 (i.e., energy, demand, or customer) for each *expense* account. This report shows
23 in great detail the classified, operating expenses by function (i.e., intangible,

1 production, transmission, distribution, etc.) These classified expenses, totaled
2 by function, match exactly the expenses shown in the income statement reports
3 (DLS-3 and DLS-7).

4 Schedules DLS-6 and DLS-10 are the Customer, Demand, and Energy Charge
5 reports for MPS and L&P respectively. These schedules show the steps taken
6 to calculate the customer, demand and energy charges; used as starting points
7 for Aquila's rate design efforts.

8 **BILLING UNITS**

9 Q. How do the results of your COS help Aquila determine rates?

10 A. The results of the COS studies serve as a foundation upon which the rate
11 designers can build.

12 Q. Were you also involved in the rate design efforts beyond providing the COS
13 studies?

14 A. Yes. I provided test year billing units for the proposed rate structure to Aquila
15 witness Charles Gray.

16 Q. Please explain.

17 A. Aquila developed customer impact software which can analyze historical
18 billing data, from Aquila's Customer Information System ("CIS"), and
19 reproduce a sample bill. Essentially, this software answers the question, "what
20 would the customer have paid with a different rate structure, with different rate
21 prices, or with both?"

22 The software can generate a report showing the original bill with the individual
23 customer, energy, and demand charges. It is also able to identify and report

1 such items as seasonal energy blocks, seasonal demand blocks, separate
2 customer charges, facility charges, etc. Collectively, these are called the billing
3 units.

4 After Aquila's Regulatory Service department had determined the new rate
5 structures that are being proposed in this case, I used the customer impact
6 software to determine the billing units (i.e., kilowatt hours in each energy
7 block, summer demand, winter demand, etc.), under that proposed structure.

8 Q. Were these the billing units you provided to Mr. Gray?

9 A. No. Recall that these billing units are based on the underlying CIS data. These
10 units represent the actual billing units from the test year, but restructured to
11 match our proposed rate. Also recall that the COS studies serve as a
12 foundation upon which the new rates are constructed. Therefore, what we still
13 needed were billing units which reflected the adjustments and normalizations
14 that were made to the COS study inputs.

15 Q. What adjustments and normalizations were made to the COS study inputs?

16 A. The COS studies used KWh sales (energy) data that had been weather
17 normalized, annualized for 365 days, adjusted to account for rate switchers,
18 adjusted for customer growth, and annualized for large customer load changes.

19 All of these adjustments and normalizations are explained in detail in Staff's
20 testimony in Case No. ER-2004-0034.

21 Q. Did you modify the billing units that the customer impact software produced?

22 A. Yes. The Regulatory Services department worked closely with Staff to
23 develop the billing units. Staff witness Janice Pyatte provided Aquila with a

1 set of adjustment factors to apply to the billing units produced by the customer
2 impact software.

3 Q. How did you apply those adjustment factors?

4 A. Aquila modified the software slightly so that it would apply the adjustment
5 factor to every customer in the database. Since the adjustment factors provided
6 by Staff witness Pyatte were distinguished by rate and by month, the software
7 was modified to identify the rate id for every customer and apply the
8 adjustment factor for the appropriate month to the billing units.

9 We worked with Staff to determine a final correction to account for the
10 customer adjustment, and to force the revenue generated by the billing units to
11 equal the revenue from Staff's final position in the revenue requirements case.
12 Those adjusted billing units were used by Aquila witness Gray.

13 Q. What recommendations are you making to the Commission?

14 A. I am recommending that the Commission endorse Aquila's COS studies and
15 approve the results to be used in designing Aquila's proposed rates.

16 Q. Does this conclude your direct testimony?

17 A. Yes.

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

In the matter of an Examination of Class Cost of Service)
And Rate Design in the Missouri Jurisdictional Electric)
Service Operations of Aquila, Inc., formerly known as)
UtiliCorp United Inc.)

Case No. EO-2002-384

County of Jackson)
) ss
State of Missouri)

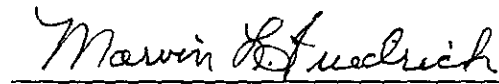
AFFIDAVIT OF DAVID L. STOWE

David L. Stowe, being first duly sworn, deposes and says that he is the witness who sponsors the accompanying testimony entitled "Direct Testimony of David L. Stowe;" 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.



David L. Stowe

Subscribed and sworn to before me this 16TH day of SEPTEMBER, 2005.



Notary Public
MARVIN L. FRIEDRICH

My Commission expires:

March 10, 2007

**Aquila Networks - MPS
Distribution Study Account Summary**

Completed By: David L. Stowe
Date: 19-Sep-05

Account	Description	Total Account Cost	Primary Percent	Cost Of Primary	Secondary Percent	Cost Of Secondary	Customer Component	Demand Component
360001	Electrical Dist. - Land	\$ 1,713,859.20	100.00%	\$ 1,713,859.20				100.00%
360002	Electrical Dist. - Land Rights/ROW	\$ 190,446.12	100.00%	\$ 190,446.12				100.00%
360051	Electrical Dist. - Land/Land Rights - Leased	\$ 22,228.32	100.00%	\$ 22,228.32				100.00%
361000	Electrical Dist. Substation Structures & Imprvmnts	\$ 3,355,434.32	100.00%	\$ 3,355,434.32				100.00%
362000	Electrical Dist. Substation Equipmt	\$ 51,234,003.72	100.00%	\$ 51,234,003.72				100.00%
364000	Electrical Dist. - Pole/Tower/Fixture	\$ 95,728,968.30	77.09%	\$ 73,795,547.08	22.91%	\$ 21,933,421.22	25.44%	74.56%
365000	Electrical Dist. - Overhead Conductors	\$ 58,807,898.70	66.60%	\$ 39,165,472.46	33.40%	\$ 19,642,426.24	9.70%	90.30%
366000	Electrical Dist. - Underground Conduit	\$ 22,114,221.75	52.55%	\$ 11,620,360.10	47.45%	\$ 10,493,861.65	75.03%	24.97%
367000	Electrical Dist. - Underground Conductors	\$ 65,941,253.55	43.91%	\$ 28,954,804.43	56.09%	\$ 36,986,449.12	87.23%	12.77%
368001	Electrical Dist. Line Transformer - Other Equipmt	\$ 30,533,014.13	5.76%	\$ 5,751,503.87	94.24%	\$ 94,182,574.89	56.05%	43.95%
368002	Electrical Dist. Line Transformer - Conventional	\$ 27,780,949.70						
368003	Electrical Dist. Line Transformer - Padmount	\$ 41,620,114.93						
369001	Electrical Dist. - Overhead Services	\$ 11,774,605.06			100.00%	\$ 11,774,605.06	100.00%	
369002	Electrical Dist. - Underground Services	\$ 36,821,152.51			100.00%	\$ 36,821,152.51	100.00%	
370001	Electrical Dist. - Meters Other	\$ 21,540,394.75			100.00%	\$ 21,540,394.75	100.00%	
370002	Electrical Dist. - Meters PURPA	\$ 2,045,595.52			100.00%	\$ 2,045,595.52	100.00%	
371000	Electrical Dist. - Installation Cust Premise	\$ 11,351,095.76			100.00%	\$ 11,351,095.76	100.00%	
373000	Electrical Dist. - Street Lighting	\$ 18,211,865.57			100.00%	\$ 18,211,865.57	100.00%	
MPS Totals		\$ 500,787,101.91		\$ 215,803,659.63		\$ 284,983,442.28		

Account	Description	Cost Of Primary	Primary Customer	Primary Demand	Cost Of Secondary	Secondary Customer	Secondary Demand
360001	Electrical Dist. - Land	\$ 1,713,859.20		\$ 1,713,859.20			
360002	Electrical Dist. - Land Rights/ROW	\$ 190,446.12		\$ 190,446.12			
360051	Electrical Dist. - Land/Land Rights - Leased	\$ 22,228.32		\$ 22,228.32			
361000	Electrical Dist. Substation Structures & Imprvmnts	\$ 3,355,434.32		\$ 3,355,434.32			
362000	Electrical Dist. Substation Equipmt	\$ 51,234,003.72		\$ 51,234,003.72			
364000	Electrical Dist. - Pole/Tower/Fixture	\$ 73,795,547.08	\$ 18,770,635.36	\$ 55,024,911.73	\$ 21,933,421.22	\$ 5,578,985.02	\$ 16,354,436.20
365000	Electrical Dist. - Overhead Conductors	\$ 39,165,472.46	\$ 3,800,617.45	\$ 35,364,855.01	\$ 19,642,426.24	\$ 1,906,101.04	\$ 17,736,325.20
366000	Electrical Dist. - Underground Conduit	\$ 11,620,360.10	\$ 8,719,221.00	\$ 2,901,139.10	\$ 10,493,861.65	\$ 7,873,964.15	\$ 2,619,897.50
367000	Electrical Dist. - Underground Conductors	\$ 28,954,804.43	\$ 25,257,275.91	\$ 3,697,528.53	\$ 36,986,449.12	\$ 32,263,279.56	\$ 4,723,169.55
368001	Electrical Dist. Line Transformer - Other Equipmt	\$ 5,751,503.87	\$ 3,223,775.44	\$ 2,527,728.44	\$ 94,182,574.89	\$ 52,790,275.05	\$ 41,392,299.84
368002	Electrical Dist. Line Transformer - Conventional				\$ -	\$ -	\$ -
368003	Electrical Dist. Line Transformer - Padmount				\$ -	\$ -	\$ -
369001	Electrical Dist. - Overhead Services				\$ 11,774,605.06	\$ 11,774,605.06	
369002	Electrical Dist. - Underground Services				\$ 36,821,152.51	\$ 36,821,152.51	
370001	Electrical Dist. - Meters Other				\$ 21,540,394.75	\$ 21,540,394.75	
370002	Electrical Dist. - Meters PURPA				\$ 2,045,595.52	\$ 2,045,595.52	
371000	Electrical Dist. - Installation Cust Premise				\$ 11,351,095.76	\$ 11,351,095.76	
373000	Electrical Dist. - Street Lighting				\$ 18,211,865.57	\$ 18,211,865.57	
MPS Totals		\$215,803,659.63	\$59,771,525.15	\$156,032,134.48	\$284,983,442.28	\$202,157,314.00	\$82,826,128.29

Schedule DLS-1: Distribution Study Report - Aquila Networks - MPS

**Aquila Networks - L&P
Distribution Study Account Summary**

Completed By: David L. Stowe
Date: 19-Sep-05

Account	Description	Total Account Cost	Primary Percent	Cost Of Primary	Secondary Percent	Cost Of Secondary	Customer Component	Demand Component
360001	Electrical Dist. - Land	\$ 540,841.72	100.00%	\$ 540,841.72				100.00%
360002	Electrical Dist. - Land Rights/ROW	\$ 85,665.21	100.00%	\$ 85,665.21				100.00%
361000	Electrical Dist. Substation Structures & Imprvmnts	\$ 1,892,325.17	100.00%	\$ 1,892,325.17				100.00%
362000	Electrical Dist. Substation Equipmt	\$ 29,287,963.85	100.00%	\$ 29,287,963.85				100.00%
364000	Electrical Dist. - Pole/Tower/Fixture	\$ 21,471,189.13	87.70%	\$ 18,831,091.71	12.30%	\$ 2,640,097.42	14.34%	85.66%
365000	Electrical Dist. - Overhead Conductors	\$ 19,163,788.41	81.69%	\$ 15,654,898.75	18.31%	\$ 3,508,889.66	9.52%	90.48%
366000	Electrical Dist. - Underground Conduit	\$ 5,067,811.77	71.54%	\$ 3,625,613.90	28.46%	\$ 1,442,197.87	63.46%	36.54%
367000	Electrical Dist. - Underground Conductors	\$ 12,867,678.43	27.45%	\$ 3,532,306.41	72.55%	\$ 9,335,372.02	83.91%	16.09%
368001	Electrical Dist. Line Transformer - Other Equipmt	\$ 5,369,112.30	5.40%	\$ 1,230,278.39	94.60%	\$ 4,138,833.91	53.65%	46.35%
368002	Electrical Dist. Line Transformer - Conventional	\$ 13,952,731.23						
368003	Electrical Dist. Line Transformer - Padmount	\$ 3,462,128.77						
369001	Electrical Dist. - Overhead Services	\$ 3,561,415.38			100.00%	\$ 3,561,415.38	100.00%	
369002	Electrical Dist. - Underground Services	\$ 7,287,337.85			100.00%	\$ 7,287,337.85	100.00%	
370001	Electrical Dist. - Meters Other	\$ 6,479,439.40			100.00%	\$ 6,479,439.40	100.00%	
370002	Electrical Dist. - Meters PURPA				100.00%	\$ -	100.00%	
371000	Electrical Dist. - Installation Cust Premise	\$ 3,007,402.12			100.00%	\$ 3,007,402.12	100.00%	
373000	Electrical Dist. - Street Lighting	\$ 3,763,920.86			100.00%	\$ 3,763,920.86	100.00%	
SJLP Totals		\$ 137,260,751.60		\$ 74,680,985.11		\$ 62,579,766.49		

Account	Description	Cost Of Primary	Primary Customer	Primary Demand	Cost Of Secondary	Secondary Customer	Secondary Demand
360001	Electrical Dist. - Land	\$ 540,841.72		\$ 540,841.72			
360002	Electrical Dist. - Land Rights/ROW	\$ 85,665.21		\$ 85,665.21			
361000	Electrical Dist. Substation Structures & Imprvmnts	\$ 1,892,325.17		\$ 1,892,325.17			
362000	Electrical Dist. Substation Equipmt	\$ 29,287,963.85		\$ 29,287,963.85			
364000	Electrical Dist. - Pole/Tower/Fixture	\$ 18,831,091.71	\$ 2,701,188.62	\$ 16,129,903.10	\$ 2,640,097.42	\$ 378,703.54	\$ 2,261,393.88
365000	Electrical Dist. - Overhead Conductors	\$ 15,654,898.75	\$ 1,489,876.71	\$ 14,165,022.04	\$ 3,508,889.66	\$ 333,941.03	\$ 3,174,948.63
366000	Electrical Dist. - Underground Conduit	\$ 3,625,613.90	\$ 2,300,887.09	\$ 1,324,726.81	\$ 1,442,197.87	\$ 915,247.61	\$ 526,950.26
367000	Electrical Dist. - Underground Conductors	\$ 3,532,306.41	\$ 2,963,922.98	\$ 568,383.42	\$ 9,335,372.02	\$ 7,833,217.31	\$ 1,502,154.71
368001	Electrical Dist. Line Transformer - Other Equipmt	\$ 1,230,278.39	\$ 660,081.27	\$ 570,197.13	\$ 21,553,693.91	\$ 11,564,203.39	\$ 9,989,490.52
368002	Electrical Dist. Line Transformer - Conventional					\$ -	\$ -
368003	Electrical Dist. Line Transformer - Padmount					\$ -	\$ -
369001	Electrical Dist. - Overhead Services				\$ 3,561,415.38	\$ 3,561,415.38	
369002	Electrical Dist. - Underground Services				\$ 7,287,337.85	\$ 7,287,337.85	
370001	Electrical Dist. - Meters Other				\$ 6,479,439.40	\$ 6,479,439.40	
370002	Electrical Dist. - Meters PURPA				\$ -	\$ -	
371000	Electrical Dist. - Installation Cust Premise				\$ 3,007,402.12	\$ 3,007,402.12	
373000	Electrical Dist. - Street Lighting				\$ 3,763,920.86	\$ 3,763,920.86	
SJLP Totals		\$ 74,680,985.11	\$ 10,115,956.67	\$ 64,565,028.44	\$ 62,579,766.49	\$ 45,124,828.50	\$ 17,454,937.99

Schedule DLS-2: Distribution Study Report - Aquila Networks - L&P

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