Exhibit No.:	
Issues:	Cost-of-Service, Fixed Cost Allocation, Variable Cost Allocation
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

Rebuttal Testimony

Of

David L. Stowe

TABLE OF CONTENTS

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

Q. Please state your name and business address.

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

Q. Are you the same David Stowe that filed direct testimony in this case on behalf of Aquila, Inc. ("Aquila")?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony will focus on the cost-of-service ("COS") studies provided by the other parties in this case through their direct testimonies. I will address the time-of-use ("TOU") allocation methods used by the Missouri Public Commission Staff ("Staff") and the Office of Public Counsel ("OPC") to distribute fixed production and transmission costs. I will explain how this allocator is based on a faulty assumption regarding the cause of fixed costs. I will also explain how this allocator is misapplied and that, as a result of this misapplication, distributes fixed production and transmission costs using an energy allocation. I will discuss errors that I have found in Staff's and the OPC's COS studies. Finally, I will discuss how the misapplication of the TOU allocator, and the errors in the studies, have affected the final results of the COS studies.

My rebuttal will focus on the Aquila – MPS service territory since the structure of the COS study for Aquila – L&P is identical while the data may be different.

Q. What recommendations do you make in your rebuttal testimony?

A. Based on the errors I found in Staff's and the OPC's COS studies, I recommend that the Missouri Public Commission ("Commission") adopt Aquila's COS study and use the resulting class revenues as the basis for designing new rates in this case.

Allocation of Fixed Production and Transmission Costs

Q. What are "fixed costs"?

A. Capital costs which are relatively constant, irrespective of the volume of discrete energy or demand transactions, are considered "fixed costs". The premise is that operating and capital costs of providing production and transmission services to a customer are fixed in nature, are proportional to the maximum capacity of the component parts, and do not vary with the quantity of energy used. For example, fixed costs include those costs incurred to purchase equipment and property such as turbines, coal mills, transmission towers, or land. These costs may be referred to as "fixed" or "capacity" interchangeably, but throughout my rebuttal testimony I will used the term "fixed" except when quoting from other witnesses' testimony.

Q. How are fixed costs normally classified?

A. Consistent with the National Association of Regulatory Utility Commissioners' Electric Utility Cost Allocation Manual ("NARUC manual") fixed costs are normally classified as capacity or demand.

Q. What type of allocator is generally used to distribute fixed production and transmission costs?

A. Traditionally, fixed production and transmission costs were distributed using a peak demand allocator, but this trend is changing. The NARUC manual states, "The prevailing belief was that utilities built plants exclusively to serve their annual system peaks as though only that single hour was important for planning... Over time it became apparent to some that hours other than the peak hour were critical to the system planner's perspective, and utilities moved toward multiple peak allocation methods.1"

Review of Staff's COS

Q. How did Staff classify fixed production and transmission costs in their COS study?

A. Staff witness Busch states, "The costs of generation facilities are directly related to the utility's generation capacity, which is determined through the utility's system planning, where many factors including both load factor and demand are considered, and are thus classified as capacity related[2]." Later, witness Busch says, "Transmission plant is generally considered to be an extension of production plant.[3]" Staff classified the fixed production and transmission costs as capacity, or demand, related.

Q. Is this how the fixed production and transmission costs were classified in the other parties' COS studies?

A. Yes.

Q. What allocator did Staff use to distribute fixed production and transmission costs?

---

[1] NARUC manual, pg. 39.
[2] Direct testimony of James A. Busch, pg 9 line 22 – pg 10 line 2
[3] Id. Id. Id. pg. 11, line 22.

A. Staff used a time-of-use ("TOU") allocator which was equivalent to the Capacity Utilization allocation method[4]. Staff's assumptions regarding fixed cost causation, their calculations of the allocator, and their application of the allocator to all the fixed costs throughout the year are inconsistent and force the TOU allocator to be an energy allocator rather than a demand allocator.

Q. Please explain.

A. Staff's fixed cost allocator is an outgrowth of Staff's underlying assumptions about the causes of those costs. Staff witness Busch describes a primary assumption in his direct testimony when he states, "Because production *capacity costs are determined by loads throughout the year*, each class's contribution to the sum of hourly class loads was used to allocate hourly production capacity costs."[5]

According to his testimony, Staff witness Busch makes the assumption that fixed production costs are caused by loads (i.e., KW) over a period of time. It is universally recognized that the measurement of a load over a period of time is, by definition, energy.

The TOU allocator, built upon the assumption that fixed costs are determined by energy use, is calculated as follows…

> "Hourly marginal production-capacity costs were derived from the hourly *marginal energy costs*. In each hour the marginal *energy costs* are summed to determine the *total energy* cost. The total *energy cost in each hour is then allocated* to the classes based on their contribution to the total load in

[4] "This is equivalent to the capacity utilization method when each increment of capacity is priced at its marginal cost." Direct testimony of James A. Busch pg. 11 line 12.
[5] Id, pg. 10, line 12. (Emphasis added.)

that hour… This is equivalent to the capacity utilization method when each increment of capacity is priced at its marginal cost.[6]"

Q. Do you agree with Staff that fixed costs are determined by energy?

A. No.

Q. Why not?

A. Fixed costs, as I have already explained, are the costs of equipment and property. These costs are capital costs that are incurred to purchase and/or install assets capable of producing, transmitting, or supporting the electrical system. They are costs that do not change throughout the year as the result of customers using more or less energy.

Q. If fixed costs are not caused by energy usage, what is the determining factor?

A. Fixed costs vary as additional assets (e.g., equipment or land) are purchased, installed, retired, or transferred. The values of those costs are primarily determined by the size and capacity of the asset. This statement is firmly grounded in fact, and can be easily demonstrated.

Q. Please explain.

A. Consider the following example which focuses on FERC Account 314; the FERC account used to track costs of steam turbo-generator equipment. According to the FERC Code of Federal Regulations, title 18, this account includes the costs of air cleaning and cooling apparatus, circulating pumps, generator hydrogen, cooling towers, cranes, etc., all of which are necessary for the turbo-generator to achieve maximum capacity. Aquila maintains a PowerPlant™ database which contains current property records for every FERC property account that allows us to see how account

[6] Id. pg 11, lines 7 – 13.

costs increase and decrease throughout the year. Table 1 below combines Account 314 cost data from the PowerPlant™ database with system energy and system peak demand data from 2002.

Month	Beginning Balance	Additions	Retirements	Trans/Adjust	Energy (MWh)	Demand (KW)
Jan	$61,550,829	$268,496	$0	$0	462,943	834,061
Feb	$61,819,325	$0	$0	$0	394,158	777,456
Mar	$61,819,325	$0	($56,918)	$0	389,893	742,294
Apr	$61,762,406	$13,868,219	($4,688,077)	$0	341,990	606,853
May	$70,942,548	$0	($473,508)	$0	376,136	873,715
Jun	$70,469,040	$0	$0	($14,440)	486,866	1,062,771
Jul	$70,454,600	$107,303	$0	$0	560,208	1,150,301
Aug	$70,561,902	$0	$0	$0	535,540	1,138,318
Sep	$70,561,902	$62,480	$0	$0	423,343	1,041,735
Oct	$70,624,382	$32,513	$0	$0	369,551	730,489
Nov	$70,656,895	$0	$0	$0	374,113	692,128
Dec	$70,656,895	$546,081	($24,652)	$0	439,078	812,063

Table 1. 2002 Account 314 changes compared to energy and demand.

Q. What does this table show?

A. The table shows that the fixed costs in Account 314 do not increase and decrease with energy as they would if the costs were caused by energy use. Rather, the table shows that these fixed costs are strictly independent of both system demand and energy.

Q. Please explain further.

A. In the 2002 calendar year, the largest change to the balance of Account 314 came in April when $13,868,219 in equipment was added and $4,688,077 in equipment was retired. The table shows that the peak demand and peak energy were lower in that month than in any other month of the year. During the summer months, when demand and energy values were at their highest levels, very little change was recorded in Account 314. The fact that these fixed costs are not dependent on the loads throughout the year is vividly apparent when the data from Table 1 is viewed in a chart as in Rebuttal Schedule DLS-1. On this schedule, the monthly change to Account 314 is charted along with the monthly system energy in megawatt hours and the monthly system peak demand in kilowatts.

The table and chart demonstrate that fixed costs are not determined or caused by system energy or demand, but instead are determined by the cost of land and equipment as it is purchased, installed, retired, or transferred. The cost of that equipment, in turn, is directly related to its maximum power handling or power producing capacity.

Q. Does the NARUC manual say that production plant costs are determined by energy?

A. Yes, it does. It should be clear from what I have already said, however, that I disagree with the NARUC manual on this point.

The NARUC manual states, "For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability (LOLP), loss of load hours (LOLH), reserve margin, or expected un-served energy (EUE); and (2) that the utility's energy load or load duration curve is an indicator of type of plant needed. The type of plant installed determines the costs of the additional capacity.[7]"

The preceding paragraph does not tell the entire story. What it does not say is that, after the type of plant is chosen to meet the criteria stated, the ultimate question which must be answered is, "How much power must the plant be capable of producing?"

---

[7] NARUC Manual, pg 38.

The answer to *that* question determines the fixed costs amount. Of course when the plant is constructed, an efficient operation and maintenance program can help the utility achieve the reliability levels (LOLP, LOLH, and EUE) that the engineers had planned. Also, many of the costs incurred to operate the plant reliably and efficiently do vary with the energy used and are tracked in separate FERC Accounts. The NARUC manual stops short of explaining these facts, and leaves the readers to draw their own conclusions. However, it is incorrect to infer that fixed costs are caused by energy usage simply because energy is a consideration during the planning stage. Later, the NARUC manual states, "There is evidence that energy loads are a major determinant of production plant costs." Yet, the evidence is never given, nor is it clear what comprises the "production plant costs". According to my research of Aquila's fixed production costs, the evidence shows that fixed production and transmission costs rise and fall independent of system energy and peak demand.

Q. If fixed costs are not caused by either the energy or the peak demand of the system, why are demand allocators used to distribute those costs to the classes?

A. The premise is that the costs should be allocated to, and recovered from, the classes that the costs were incurred to serve. Since production and transmission equipment are purchased for the benefit of every class of customer, and since the value of that equipment is related to the capacity or demand of the equipment, analysts consider capacity (i.e., demand) as the "link" connecting fixed costs to the classes. However, this link between fixed costs and capacity is merely the starting point when attempting to determine a proper fixed cost demand allocator. The questions still remain; should the allocator use coincident or non-coincident demand? Should it include multiple peaks or a single peak? Should the allocator use system, class, or customer demands?

Q. Does the NARUC manual discuss the allocation of fixed production and transmission costs allocation?

A. Yes. The NARUC manual describes the history of fixed cost allocation this way. "In the past, utility analysts thought that production plant costs were driven only by system maximum peak demands. The prevailing belief was that utilities built plants exclusively to serve their annual system peaks as though only that single hour was important. Correspondingly, cost of service analysts used a single maximum peak approach to allocate production costs. Over time it became apparent to some that hours other than the peak hour were critical from the system planner's perspective, and utilities moved toward multiple peak allocation methods.[8]"

The NARUC manual goes on to describe a variety of allocation methods including multiple coincident peak, multiple non-coincident peak, and methods that combine peak demand and energy weighted components.

Q. What are "energy-weighted" demand allocators?

A. Energy-weighted demand allocators are simply demand allocators that include an average energy component. Demand allocators based on a single maximum peak place excessive responsibility on certain customer classes and miss others. Using multiple demand peaks eliminates this somewhat, but even multiple peak allocators can miss certain classes entirely.

[8] NARUC Manual. pg. 39.

Q. Can you give an example of a customer class that might be missed or under represented by a single or multiple peak allocator

A. Yes. The lighting class is one that is under represented using a single or multiple peak demand allocator. This is because the lighting class contributes very little, if anything, to peak demand. Using an energy-weighted demand allocator, however, will assign some level of demand to the lighting class or classes with demand characteristics similar to it.

Q. Doesn't the use of energy-weighted demand allocators assume that the costs distributed by those allocators are caused by energy?

A. Not at all. As I have already said, energy-weighted demand allocators are used to fairly assign demand related costs to every class of customer, not because energy usage is believed to cause those costs.

Today, most if not all COS analysts, including those at Aquila, have moved away from single and multiple peak allocation methods and are using allocation methods which combine multiple peak and energy components. Aquila has used some form energy-weighted demand allocator for over a decade. In the current COS study, we have used an Average and Excess allocator that combines average energy with the three highest coincident demand peaks. Others analyst use time-differentiated allocation methods to assist in developing time-differentiated rates such as critical peak pricing (CPP), real time pricing (RTP), and time-of-use (TOU). While growing in popularity, time-differentiated techniques are less common than the other methods due to the elaborate supporting studies that are required.

Q. Can you give examples of energy-weighted demand allocators?

A. Methods such as "Average and Excess", "Equivalent Peaker", "Base and Peak", and the time-differentiated methods all result in energy-weighted demand allocators.

Q. Is Staff's TOU allocator one of the time-differentiated allocators described in the NARUC manual?

A. No. The NARUC manual describes a variety of methods for determining "time-differentiated" COS studies. These methods are broadly described as production stacking methods, system planning approaches, the base-intermediate-peak method, the LOLP (loss of load probability) production costs method, and the probability of dispatch method.

Staff's TOU allocator is similar to the production stacking method, insofar as it assumes a certain percentage of fixed costs are allocated on energy and the remainder on demand. In other words, there is a certain mix, or stack, of generating units which meet the requirements of a base level of load, and the fixed costs of that base generation mix is the energy portion of the capacity costs. The remainder of the fixed costs are allocated on demand.

Conversely, Staff's TOU allocator is *unlike* the time-differentiated methods described in the NARUC manual in a number of critical ways.

Q. How is Staff's TOU allocator different from the time-differentiated allocations described in the NARUC manual?

A. First, Staff's TOU allocator is not supported by the requisite "base level of load" and "generation mix" studies. These studies are essential in determining which portion of the capacity costs should be allocated as energy and which portion as demand. Without them, it is impossible to know which portion of capacity costs the TOU allocators should distribute as energy and demand.

Second, Staff's TOU allocator is not part of a COS study that has identified time-differentiated costs. Staff's COS study used cost data which came from the stipulated agreement in Aquila's previous revenue requirements electric rate case[9]. This agreement has been termed a "black box" agreement because, while the resulting revenues are known, the specific cost details are not. Staff presented direct testimony in that case which included schedules showing adjustments made to energy and revenue values. These adjustments "updated" the test year for "known and measurable" transactions as of September of 2003. Yet, the demand and energy data upon which Staff's TOU allocator was calculated does not contain those adjustments. The dataset Staff used to develop the TOU allocators had a *different* adjustment, one for weather normalization, made to it. With such a starting point, it is impossible to identify time-differentiated costs or to match them to hourly loads. That is to say, there is no way to determine the costs of production and transmission during specific time periods throughout the day, month, or year.

Finally, Staff's COS makes no attempt to determined time-differentiated rates. Instead, Staff's COS uses the same basic data and logic as Aquila's which is designed to determine, at best, seasonally differentiated rates for Aquila's customer classes. Staff's use of the TOU allocator in this case, therefore, is something of a hybrid; applying a method best suited for CPP or RTP rates to data that came out of a black

[9] Case No. ER-2004-0034.

box settlement. The net result was an energy allocation applied to all fixed production costs.

Q. Please explain what you mean.

A. In describing the time-differentiated methods, the NARUC manual says, "The basic principle of such methods is to identify the configuration of generating plants that would be used to serve some specified base level of load[, and] to classify the costs associated with those units as energy related. The choice of the base level of load is crucial because it determines the amount of production plant cost to classify as energy-related.[10]"

What this means is that a valid time-differentiated method will first identify a "base level of load" and then determine the configuration of base, intermediate, and peaking units that serve that base load. The costs associated with this "base generation mix" are then classified as energy and the remainder as demand.

Q. What approach did Staff take?

A. The "base level of load", to which Staff applies its TOU allocator, is the sum of the class non-coincident peaks. The corresponding "base generation mix" which Staff assumes will meet the "base level of load", consists of every plant on the system.

Q. What does this mean?

A. In theory, Staff is setting aside every generating unit to be classified as energy, leaving nothing to classify as demand. When Staff applies the TOU allocator to the total fixed

[10] NARUC manual. pg. 60.

production costs over the entire year, Staff allocates all fixed production and transmission costs as energy.

In its direct testimony, Staff admits that it *classifies* fixed production and transmission costs as demand, and implies that its TOU allocator is a valid energy-weighted demand allocator; fairly allocating a portion of fixed production and transmission cost to the classes. Yet in practice, Staff calculates the TOU allocators on energy and distributes all the fixed production costs to the classes using them. This is logically inconsistent.

Q. In their direct testimony, does Staff explain benefits of using the TOU allocation method?

A. Yes. In discussing the value of the TOU method, Staff witness Busch writes, "it has the characteristic that every customer, large or small, residential or industrial, pays exactly the same price as every other customer taking service in the same hour. In this respect, TOU allocations mimic a truly competitive retail electricity market."

Q. Does the TOU allocation method have the characteristic that every customer pays exactly the same price as every other customer in the same hour?

A. Not as it was applied in Staff's embedded COS study. The ultimate goal, in this proceeding, is to develop rates for every customer class that will collect revenue to cover the costs incurred for that class plus the approved return. In addition, Aquila is ordered to use data, which came out of the previous electric revenue requirements case, to meet that goal. While marginal cost techniques are popular and helpful when applied properly, using them in this instance to model Aquila's costs is a mistake. Applauding the idea that the TOU allocation method, when applied properly, mimics a truly competitive retail electricity market, particularly in light of the fact that Aquila is a regulated monopoly, is meaningless.

Q. How do Staff's TOU demand allocators compare to energy allocators?

A. Staff's final TOU production demand allocator, for residential customers, is just 4.16% above the energy allocator that was calculated as the ratio of class annual energy to system annual energy. Similarly, the final TOU transmission demand allocator, again for the residential class, was just 1.23% above the energy allocator. In both cases, these where the largest deviations when compared to the energy allocator. A comparison of the TOU and energy allocators is shown in Table 2 below.

TOU Allocators	Prod. Capacity	Prod. Energy	Trans. Capacity	ENERGY	DIFF Prod Capacity	DIFF Prod Energy	DIFF Trans. Capacity
RES GEN	36.40%	32.00%	31.41%	31.34%	5.07%	0.67%	0.07%
RES SH	13.22%	14.08%	15.29%	14.13%	-0.90%	-0.05%	1.16%
SGS	15.69%	15.31%	15.35%	15.26%	0.43%	0.06%	0.09%
LGS	14.46%	15.40%	15.34%	15.53%	-1.08%	-0.13%	-0.20%
MODINE	0.10%	0.12%	0.12%	0.12%	-0.02%	0.00%	0.00%
TES	0.13%	0.13%	0.13%	0.14%	0.00%	0.00%	-0.01%
LIGHTING	0.41%	0.74%	0.69%	0.80%	-0.39%	-0.06%	-0.11%
LPS	19.59%	22.21%	21.68%	22.69%	-3.10%	-0.48%	-1.01%
TOTAL	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**0.00%**	**0.00%**	**0.00%**

Table 2: Comparison of Staff's TOU and Energy Allocators

Q. What is the impact on the COS study of allocating fixed production and transmission costs using the TOU allocator?

A. The answer is explained in Table 3 on the following page. This table shows the results of all the parties' COS studies which were developed using identical values for total fixed costs, total expenses, and total revenue. Every party split distribution plant by voltage level using the same primary and secondary percentages, and every party shifted dollars between classes to achieve identical rates of return from each class.

However, only three of the four parties (the OPC being the exception) used the same customer and demand percentages when classifying distribution fixed and variable

A. costs.

	AQUILA			STAFF		SIEUA		OPC	
MPS	($)	(%)		($)	(%)	($)	(%)	($)	(%)
RES-GEN	$15,898,191	13.09%	8.22%	$5,382,207	3.16%	$15,216,349	8.95%	($1,788,394)	-1.04%
RES-SH	($1,911,037)	-3.93%							
SGS-S	($5,246,815)	-10.50%	-10.52%	($1,880,429)	-3.49%	($5,269,377)	-9.78%	($3,166,113)	-5.79%
SGS-P	($15,562)	-20.70%							
LGS-S	($6,570,348)	-15.46%	-14.91%	($3,463,580)	-7.84%	($6,174,218)	-13.97%	($1,547,506)	-3.45%
LGS-P	($60,034)	-4.27%							
LGS-SF	$41,663	15.16%							
LPS-S	($2,249,538)	-8.62%	-6.86%	$1,418,776	2.78%	($3,812,332)	-7.46%	$6,370,484	12.24%
LPS-P	($1,255,689)	-5.03%							
S&C	($71,141)	-2.43%							
MUNI-WPR	$132,822	14.85%							
MODINE	$23,008	8.98%		$74,534	13.21%	$39,578	15.45%	$131,529	22.86%
THERM	$21,090	6.85%							
LIGHTS	$1,263,390	24.47%		($1,531,508)	-29.64%				

Table 3: COS study result comparison.

Q. What are the main differences in the parties' COS studies?

A. The fundamental difference in the COS studies is the production and transmission allocator used by the parties. Aquila and SIEUA used Average & Excess demand allocators; Aquila relied on the three highest coincident peaks (A&E-3CP) and SIEUA used the three highest non-coincident peaks to calculate the excess portions (A&E-3NCP). Staff and the OPC used Staff's TOU allocators, but the OPC modified the input values slightly so that its allocators are shifted beyond the pure energy values from Staff's. The COS studies contained other differences, of course, and those will be discussed later in my rebuttal testimony, but it was the fixed cost allocator, that accounted for the vast majority of variance between the parties' COS studies.

Q. What are the consequences of these differences?

A. The impact of the TOU allocators is enormous. For instance, Aquila's COS study found that additional revenue totaling $13,987,154 should be collected from the residential classes to bring them to a level return of 8.617%. Staff's COS study found that $5,382,207 should be collected from this same class. This difference of $8,604,947 is mostly due to Staff's use of an energy allocator and Aquila's use of an energy-weighted demand allocator to distribute fixed costs.

Allocation of Variable Production Costs

Q. What are variable production costs?

A. The operating costs and expenses which vary with of the volume of energy transactions are considered variable costs. For example, fuel expenses or purchased energy costs are variable costs because they rise and fall in a direct relationship with increased and decreased energy use.

Q. Please explain?

A. In a process similar to that described above for account 314, I collected data for FERC account 555.1 Purchased Power: Energy, and combined it with system energy data for the calendar year 2002 in table 4 on the following page.

Q. What does this table show?

A. The table shows a clear correlation between the purchased energy costs in account 555.1 and the system energy and peak demand. This relationship is even more apparent when viewed on a graph as in Rebuttal Schedule DLS- 2.

Month	Account 555.1 Purchased Energy ($)	System Energy (MWh)
Jan	$2,106,721	462,943
Feb	$4,602,240	394,158
Mar	$4,623,603	389,893
Apr	$1,230,246	341,990
May	$3,091,024	376,136
Jun	$3,632,959	486,866
Jul	$8,522,646	560,208
Aug	$9,967,512	535,540
Sep	$2,338,507	423,343
Oct	$2,039,436	369,551
Nov	$2,083,441	374,113
Dec	$2,196,597	439,078

Table 4: 2002 Account 555.1 changes compared to energy.

Q. How are variable costs usually classified?

A. Variable costs are usually classified as energy.

A. How should variable costs be allocated?

A. Variable costs are usually distributed using an energy allocator.

Q. Did Staff use an energy allocator to distribute variable costs?

A. Yes. Staff used the same TOU allocators to distribute variable costs as they used to distribution fixed costs. As I have already explained, the assumptions, calculations, and particularly the application of the TOU allocators show them to be energy allocators.

<u>Review of OPC's COS Study</u>

Q. Have you reviewed the COS study that was performed by the OPC?

A. Yes I have.

Q. Have you discovered anything in that COS study that leads you to believe the OPC study contains errors and therefore cannot be relied upon?

A. Yes. In direct testimony, OPC witness Meisenheimer explains that her COS study distributes fixed production costs on a TOU allocator similar to Staff's claiming, "Both demand and energy characteristics of a system's loads are important determinants of production plant costs.[11]" By this statement, witness Meisenheimer admits to holding the same erroneous assumptions regarding fixed costs as does Staff. Specifically, that demand and energy characteristics of a system's loads determine fixed costs. Witness Meisenheimer has modified Staff's TOU allocators to achieve a "demand" allocator which is shifted to the extreme side of the energy allocator values.

Q. Please explain.

A. In general, when costs are allocated demand, customer classes with a low load factor will be allocated a greater percentage of the costs. This is considered appropriate because low load factor classes bear more of the responsibility for peak demand costs. Conversely, when costs are allocated on energy, customer classes with a higher load factor are allocated a greater percentage of the costs. Again, this is considered appropriate because high load factor customers are responsible for a greater portion of the energy costs. In general, residential and small general service customers make up the majority of low load factor customers, and large general service and large power service customer make up the majority of high load factor customers.

If a COS analyst distributes demand related costs using an allocator based on energy, the large general service and large power service classes would receive an inappropriately large portion of these costs. So, if a pure energy allocator was used to

[11] Direct Testimony of Barbara Meisenheimer, pg. 5, lines 20 – 21.

distribute demand related costs, the large general service and large power service classes would receive and even larger percentage of these costs even though they are *not* the classes primarily responsible for those costs.

The changes made by witness Meisenheimer to Staff's TOU allocator has resulted in a "demand" allocator which distributes more of the fixed costs to the large customers than would have resulted if using a pure energy allocator.

Witness Meisenheimer makes no attempt to explain these changes except to say that the method is a "reasonably close approximation to the TOU method which the Commission has previously determined reasonable[12]".

Q. What else have you discovered?

A. OPC witness Meisenheimer provided work papers which support her direct testimony schedules. In one of those work papers[13], I found that the basic energy and demand data does not match that used by Aquila or Staff in the COS performed by those parties. These erroneous demand and energy values serve as inputs to the final calculation of the TOU allocators thereby adding inaccuracy to the faulty assumptions.

Q. Please explain.

A. The work papers of the OPC show the calculation of the Average and 12 month non-coincident peak ("A&P-12NCP") allocator that is subsequently used to distribute fixed costs. In the very first step of the calculation, the OPC collects data in a table titled "NCP Demands'. The NCP demand for the Residential class in the month of January, 2002, is given as 525.553 MW. This value is the demand at the generator which

---

[12] Id. pg. 6, lines 1-2.
[13] File 'MPS Direct ER-2002-324-2005.xls', tab 'WP-MPSAnnEnergyGen'

means that losses have been taken into account. Aquila's corresponding demand values are; System CP of 512.108 MW, Class NCP of 639.607MW, and Customer NCP of 1,323.242 MW. The OPC's NCP demand values do not match any of those used by Aquila in their COS study, but they came closest to the Aquila's system CP values.

Later in its calculation of the A&P-12NCP allocator, the OPC relies on data which it labels "CP Demands', and which are clearly totaled for all classes. Here again, the values do not correspond to those used by Aquila in its COS study. The errors in the inputs to the OPC's calculations, along with the faulty assumptions regarding the determination of fixed costs, makes the OPC's COS study unreliable.

Q. What other inconsistencies did you find in the OPC's COS study?

A. OPC witness Meisenheimer's direct testimony regarding the allocation of distribution plant contains a number of inconsistencies and errors.

Q. Please explain.

A. With respect to the allocation of distribution plant, OPC witness Meisenheimer states, "... with the exception of service drops and meters, most of the facilities between the utility customer's point-of-service and the distribution substation are shared facilities. Since *no portion of such facilities are directly related to the number of customers, the associated costs are best classified as demand related, rather than customer related.*[14]" Yet, on the next page of her direct testimony, witness Meisenheimer explains that she did, in fact, classify a significant portion of these distribution costs as

[14] Direct Testimony of Barbara Meisenheimer. pg. 6, line 23 through pg. 7 line 4 (emphasis added).

customer. Witness Meisenheimer also distinguishes between primary and secondary distribution plant, but that distinction only makes the logic behind the OPC's classification of distribution plant all the more confusing.

Q. How does the OPC's distinction of primary and secondary distribution make the logic behind their classification more confusing?

A. OPC witness Meisenheimer contends that no portion of certain distribution facilities should be classified as customer. Specifically, witness Meisenheimer is referring to FERC accounts 364 through 368. Surprisingly, witness Meisenheimer then classifies a significant portion of these facilities as customer, but for *secondary* distribution only. She classifies the entire primary system as demand. Witness Meisenheimer does not attempt to explain her reasoning behind her classification process so one is left to wonder if this inconsistency is an oversight or intentional.

What we do know is that by classifying secondary distribution costs as both customer and demand, witness Meisenheimer is admitting that at least *some* of the distribution system was installed to meet the customers need for service rather than the demand, even though in direct testimony she argues against this. By classifying the primary system only as demand, witness Meisenheimer is suggesting that that *none* of the distribution system was constructed to meet the customers need for service rather than the demand, which argues against her classification of secondary plant.

The underlying assumption behind this type of inconsistency appears to be that the classification of plant as customer or demand is dependent on its operation at primary or secondary voltages.

Q. Does the operating voltage of plant determine how it will be classified?

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 J. MATT TRACY

J. Matt Tracy, being first duly sworn, deposes and says that he is the witness who sponsors the accompanying testimony entitled "Rebuttal Testimony of J. Matt Tracy;" 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.

J. Matt Tracy

J. Matt Tracy

Subscribed and sworn to before me this 12th day of October, 2005.

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