Exhibit No.:	
Witness:	Maurice Brubaker
Type of Exhibit:	Direct Testimony
Issue:	Cost of Service
Sponsoring Party:	Ag Processing, Inc. Federal Executive Agencies Sedalia Industrial Energy Users' Association
Case No.:	EO-2002-384

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

Direct Testimony and Schedules of

Maurice Brubaker

On behalf of

Ag Processing, Inc.
Federal Executive Agencies
Sedalia Industrial Energy Users' Association

Project 7796
September 19, 2005

BRUBAKER & ASSOCIATES, INC.
ST. LOUIS, MO 63141-2000

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

STATE OF MISSOURI)
) SS
COUNTY OF ST. LOUIS)

Affidavit of Maurice Brubaker

Maurice Brubaker, being first duly sworn, on his oath states:

1. My name is Maurice Brubaker. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000. We have been retained by Ag Processing, Inc., Federal Executive Agencies and the Sedalia Industrial Energy Users' Association in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes are my direct testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. EO-2002-384.

3. I hereby swear and affirm that the testimony and schedules are true and correct and that they show the matters and things they purport to show.

Maurice Brubaker

Maurice Brubaker

Subscribed and sworn to before this 16th day of September 2005.

CAROL SCHULZ
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis County
My Commission Expires: Feb. 26, 2008

Carol Schulz

Notary Public

My Commission Expires February 26, 2008.

Before the Public Service Commission
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Direct Testimony of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and president of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of Ag Processing, Inc., Federal Executive Agencies, and the Sedalia Industrial Energy Users' Association. These customers purchase large amounts of energy from Aquila Networks, MPS and L&P.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of my testimony is to present the results of electric system class cost of service studies for MPS and L&P, and to explain how they should be used.

Q WHAT IS THE ORIGIN OF THIS PROCEEDING?

A This cost of service/rate design case was a spin-off from a 2002 rate case. Its purpose was to provide a separate forum for a careful and detailed analysis of cost of service and rate design issues. As part of this process, various technical conferences were held and Aquila conducted load research, performed other studies and ultimately produced a preliminary cost of service study.

In the meantime, Aquila filed a rate case in MPSC Case No. ER-2004-0034. This case was settled, and as part of that settlement, an across-the-board revenue increase was ordered. This preserved the cost of service/rate design issues pending resolution in this cost of service/rate design case.

Q WHAT IS THE RELATIONSHIP BETWEEN THIS PROCEEDING AND THE NOW PENDING RATE CASE, MPSC CASE NO. ER-2005-0436?

A The interclass revenue alignments and any rate design modifications that are found appropriate in this case should be implemented in the context of the decision finding the appropriate revenue requirement for Aquila in MPSC Case No. ER-2005-0436. In this manner, relitigation of cost of service, revenue allocation and rate design issues will be avoided. I discuss the implementation methodology in more detail later in my testimony

Q HOW IS YOUR TESTIMONY ORGANIZED?

A First, I present an overview of cost of service principles and concepts. This includes a description of how electricity is produced and distributed as well as a description of the various functions that are involved; namely, generation, transmission and distribution. This is followed by a discussion of the typical classification of these functionalized costs into demand-related costs, energy-related costs and customer-related costs.

With this as a background, I then explain the various factors which should be considered in determining how to allocate these functionalized and classified costs among customer classes. I utilize examples drawn from the L&P system.

Finally, I present the results of the detailed cost of service analysis for both the L&P and MPS systems. These cost studies indicate the degree to which individual customer class revenues should be increased or decreased to put them in line with the cost incurred in providing the service to the respective classes. This analysis and interpretation is then followed by recommendations with respect to the alignment of class revenues with class costs based on the results of these class cost of service studies.

The interclass revenue adjustments that take place as a result of considering these class cost of service studies (see Schedule 6) should be transferred into the pending general rate proceedings of L&P and MPS in MPSC Case No. ER-2005-0436.

<u>COST OF SERVICE PROCEDURES</u>

<u>Overview</u>

Q PLEASE DESCRIBE THE COST ALLOCATION PROCESS.

A The objective of *cost allocation* is to determine what proportion of the utility's total revenue requirement should be recovered from each customer class. As an aid to this determination, cost of service studies are usually performed to determine the portions of the total costs that are incurred to serve each customer class. The cost of service study identifies the cost responsibility of the class and provides the foundation for revenue allocation and rate design. For many regulators, cost-based rates are an expressed goal. To better interpret cost allocation and cost of service studies, it is important to understand the production and delivery of electricity.

<u>Electricity Fundamentals</u>

Q IS ELECTRICITY SERVICE LIKE ANY OTHER GOODS OR SERVICES?

A No. Electricity is different from most other goods or services purchased by consumers. For example:

- It cannot be stored; must be delivered as produced;
- It must be delivered to the customer's home or place of business;
- The delivery occurs instantaneously when and in the amount needed by the customer; and
- Both the total quantity used (energy or kWh) by a customer <u>and</u> the rate of use (demand or kW) are important.

These unique characteristics differentiate electric utilities from other service-related industries.

The service provided by electric utilities is multi-dimensional. First, unlike most vital services, electricity must be delivered at the place of consumption – homes, schools, businesses, factories – because this is where the lights, appliances, machines, air conditioning, etc. are located. Thus, every utility must provide a path through which electricity can be delivered regardless of the customer's **demand** and **energy** requirements at any point in time.

Even at the same location, electricity may be used in a variety of applications. Homeowners, for example, use electricity for lighting, space conditioning, and to operate various appliances. At any instant, several appliances may be operating (e.g., lights, refrigerator, TV, air conditioning, etc.). Which appliances are used and when reflects the second dimension of utility service–the rate of electricity use or **demand**. The demand imposed by customers is an especially important characteristic because the maximum demands determine how much capacity the utility is obligated to provide.

Generating units, transmission lines and substations and distribution lines and substations are rated according to the maximum demand that can be safely imposed on them. (They are not rated according to average annual demand; that is, the amount of energy consumed during the year divided by 8,760 hours.) On a hot summer afternoon when customers demand 2,000 megawatts (MW) of electricity, the utility must have at least 2,000 MW of generation, plus additional capacity to provide adequate reserves, so that when a consumer flips the switch, the lights turn on, the machines operate and heating and air conditioning systems heat and cool our homes, schools, offices, and factories.

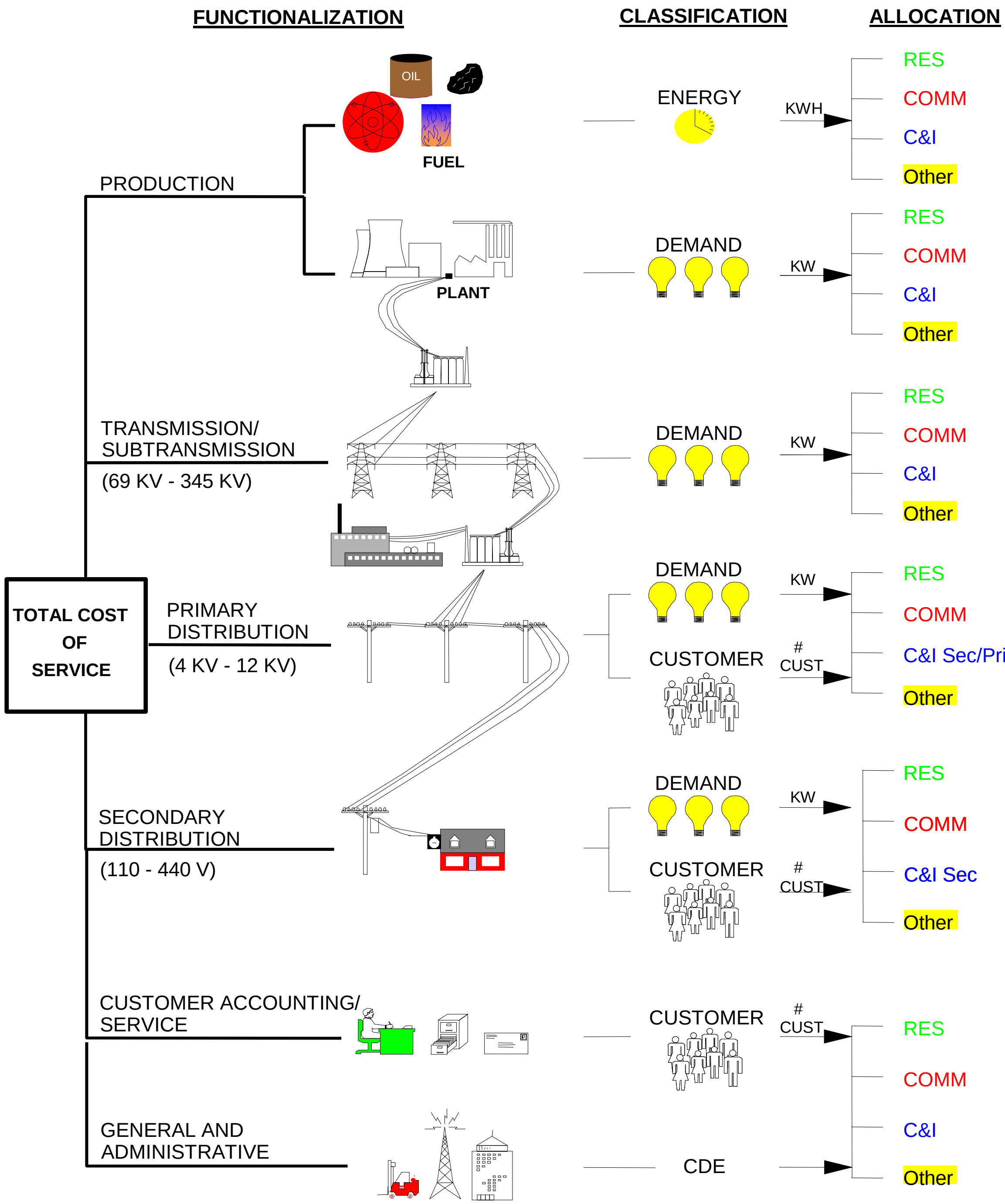
Satisfying customers' demand for electricity over time–providing **energy**–is the third dimension of utility service. It is also the dimension with which many people are most familiar, because people often think of electricity simply in terms of kilowatthours. To see one reason why this isn't so, consider a more familiar commodity–tomatoes, for example.

The tomatoes we buy at the supermarket for about $2.00 a pound might originally come from Florida where they are bought for about 30¢ a pound. In addition to the cost of buying them at the point of production, there is the cost of bringing them to the state of Missouri and distributing them in bulk to local wholesalers. The cost of transportation, insurance, handling and warehousing must be added to the original 30¢ a pound. Then they are distributed to neighborhood stores, which adds more handling costs as well as the store's own costs of light, heat, personnel and rent. Shoppers can then purchase as many or few tomatoes as they desire at their convenience. In addition, there are losses from spoilage and damage in handling. These "line losses" represent an additional cost which must be recovered in the final price. What we are really paying for at the store is not only the vegetable itself, but the <u>service</u> of having it available in convenient amounts and locations. If we took the time and trouble (and expense) to go down to the wholesale produce distributor, the price would be less. If we could arrange to buy them in bulk in Florida, they would be still cheaper.

As illustrated in Figure 1, electric utilities are similar, except that in most cases (including Missouri), a single company handles everything from production on down through wholesale (bulk and area transmission) and retail (distribution to homes and stores). The crucial difference is that, unlike tomatoes producers and distributors, electric utilities have an obligation to provide continuous reliable service. The obligation is assumed in return for the exclusive right to serve all customers located within its territorial franchise. In addition to satisfying the energy (or kilowatthour) requirements of its customers, the obligation to serve means that the utility must also provide the necessary facilities to attach customers to the grid (so that service can be used at the point where it is to be consumed) and these facilities must be responsive to changes in the kilowatt demands whenever they occur.

Figure 1

PRODUCTION AND DELIVERY OF ELECTRICITY



A CLOSER LOOK AT THE COST OF SERVICE STUDY

Q PLEASE EXPLAIN HOW A COST OF SERVICE STUDY IS PREPARED.

A To the extent possible, the unique characteristics that differentiate electric utilities from other service-related industries should be recognized in determining the cost of providing service to each of the various customer classes. The basic procedure for conducting a class cost of service study is simple. In an allocated cost of service study, we identify the different types of costs (**functionalization**), determine their primary causative factors (**classification**) and then apportion each item of cost among the various rate classes (**allocation**). Adding up the individual pieces gives the total cost for each class.

Functionalization

Q PLEASE EXPLAIN FUNCTIONALIZATION.

A Identifying the different levels of operation is a process referred to as **functionalization**. The utility's investment and expenses are separated by function (production, transmission, etc.). To a large extent, this is done in accordance with the Uniform System of Accounts.

Referring to Figure 1, at the top level there is generation. The next level is the extra high voltage transmission and subtransmission system (34,500 to 345,000 volts). Then the voltage is stepped down to primary voltage levels of distribution–4,160 to 12,000 volts. Finally, the voltage is stepped down by pole transformers at the "secondary" level to 110/220 volts used to serve homes, barber shops and the like. Additional investment and expenses are required to serve customers at secondary voltages, compared to the cost of serving customers at higher voltage.

Each additional transformation, thus, requires additional investment, additional expenses and results in some additional electrical losses. To say that "a kilowatthour is a kilowatthour" is like saying that "a tomato is a tomato." It's true in one sense, but when you buy a kilowatthour at home you're not only buying the energy itself but also the <u>service</u> of having it delivered right to your doorstep in convenient form. Those who buy at the bulk or wholesale level – like large power service customers–pay less because some of the expenses to the utility are avoided. (Actually, the expenses are borne by the customer who must invest in his own transformers and other equipment.)

<u>Classification</u>

Q WHAT IS CLASSIFICATION?

A Once the costs have been functionalized, the next step is to identify the primary causative factor (or factors). This step is referred to as **classification**. Costs are classified as demand-related, energy-related or customer-related.

Looking at the production function, the amount of production plant capacity required is primarily determined by the <u>peak</u> rate of usage during the year. If the utility anticipates a peak demand of 2,000 megawatts – it must install and/or contract for enough generating capacity to meet that anticipated demand (plus some reserve to compensate for variations in load and capacity that is temporarily unavailable).

There will be many hours during the day or during the year when not all of this generating capacity will be needed. Nevertheless, it must be in place to meet the <u>peak</u> demands on the system. Thus, production plant investment is usually classified to demand. **Regardless of how production plant investment is classified, the associated capital costs** (which include return on investment, depreciation, fixed operation and maintenance expenses, taxes and insurance) **are fixed;** that is, **<u>they do not vary with the amount of kilowatthours generated and sold</u>**. These fixed costs are determined by the amount of capacity (i.e., kilowatts) which the utility must install to satisfy its obligation-to-serve requirement.

On the other hand, it is easy to see that the amount of fuel burned–and therefore the amount of fuel expense–is closely related to the amount of energy (number of kilowatthours) that customers use. Therefore, fuel expense is an energy-related cost.

Most other O&M expenses are fixed and therefore are classified as demand-related. Variable O&M expenses are classified as energy-related. Demand-related and energy-related types of operating costs are not impacted by the number of customers served.

Customer-related costs are a third major category. Obvious examples of customer-related costs include the investment in meters and service drops (the line from the pole to the customer's facility or house). Along with meter reading, posting accounts and rendering bills, these "customer costs" may be several dollars per customer, per month. Less obvious examples of customer-related costs may include the investment in other distribution accounts.

A certain portion of the cost of the distribution system–poles, wires and transformers–is required simply to attach customers to the system, regardless of their demand or energy requirements. This minimum or "skeleton" distribution system may also be considered a customer-related cost since it depends primarily on the number of customers, rather than demand or energy usage.

Figure 2, as an example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach

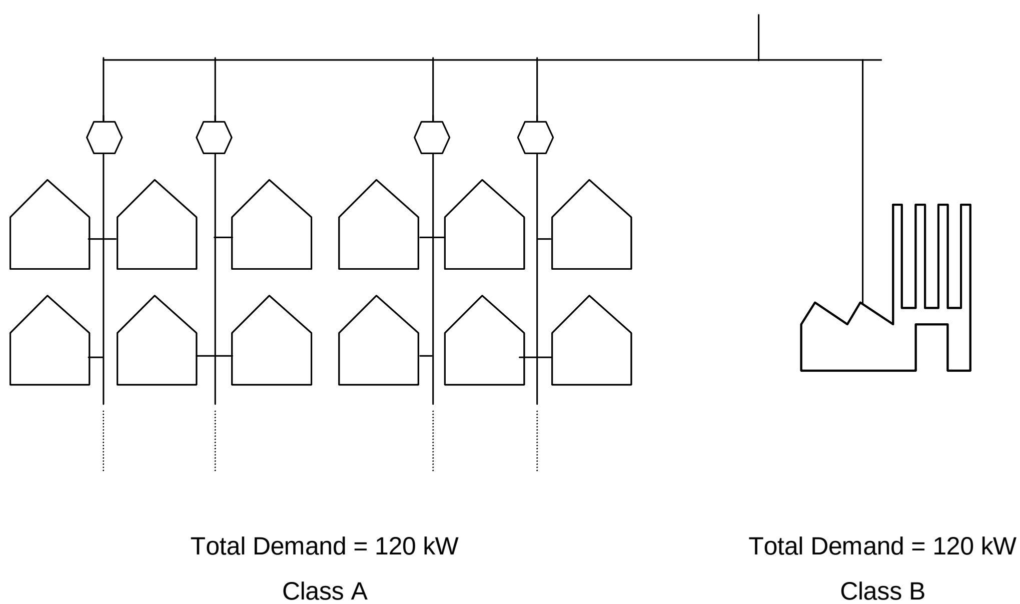
Class A is designed to serve 12 customers, each with a 10-kilowatt load, having a total demand of 120 kW. This is the same total demand as is imposed by Class B, which consists of a single customer. Clearly, a much more extensive distribution system is required to attach the multitude of small customers (Class A), than to attach the single larger customer (Class B), even though the total demand of each customer class is the same.

Even though some additional customers can be attached without additional investment in some areas of the system, it is obvious that attaching a large number of customers requires investment in facilities, not only initially but on a continuing basis as a result of the need for maintenance and repair.

To the extent that the distribution system components must be sized to accommodate additional load beyond the minimum, the balance is a demand-related cost. Thus, the distribution system is classified as both demand-related and customer-related.

Figure 2

Classification of Distribution Investment



Demand vs. Energy Costs

Q WHAT IS THE DISTINCTION BETWEEN DEMAND-RELATED COSTS AND ENERGY-RELATED COSTS?

A The difference between demand-related and energy-related costs also explains the fallacy of the argument that "a kilowatthour is a kilowatthour." For example, Figure 3, compares the electrical requirements of two customers, A and B, each using 100-watt light bulbs.

Customer A turns on all five of his/her 100-watt light bulbs for two hours. Customer B, by contrast, turns on two light bulbs for five hours. Both customers use the same amount of energy–1,000 watthours or 1 kilowatthour (kWh). However, Customer A utilized electric power at a higher rate, 500 watts per hour or 0.5 kilowatts (kW), than Customer who demanded only 200 watts per hour or 0.2 kW.

Although both customers had precisely the same kWh energy usage, Customer A's kW demand was 2.5 time Customer B's. Therefore, the utility must install 2.5 times as much generating capacity for Customer A as for Customer B. The cost of serving Customer A, therefore, is much higher.

Q DOES THIS HAVE ANYTHING TO DO WITH THE CONCEPT OF LOAD FACTOR?

A Yes. Load factor is an expression of how uniformly a customer uses energy. In our example of the light bulbs, the load factor of Customer B would be higher than the load factor of Customer A because the use of electricity was spread over a longer period of time, and the number of kilowatthours used for each kilowatt of demand imposed on the system is much greater in the case of Customer B.

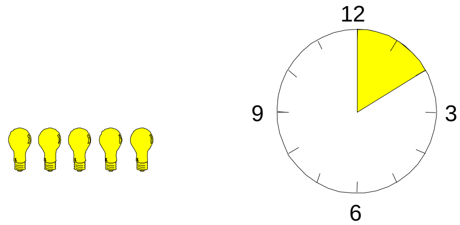
Mathematically, load factor is the average rate of use divided by the peak rate of use. A customer with a higher load factor is less expensive to serve, on a per kilowatthour basis, than a customer with a low load factor, irrespective of size.

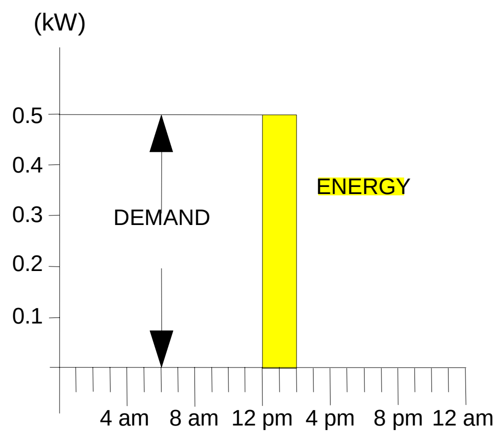
Consider also the analogy of a rental car which costs $40/day and 20¢/mile. If Customer A drives only 20 miles a day, the average cost will be $2.20/mile. But for Customer B, who drives 200 miles a day, spreading the daily rental charge over the total mileage gives an average cost of 40¢/mile. For both customers, the fixed cost rate (daily charge) and variable cost rate (mileage charge) are identical, but the <u>average total</u> cost per mile will differ depending on how intensively the car is used. Likewise, the average cost per kilowatthour will depend on how intensively the generating plant is used. A low load factor indicates that the capacity is idle much of the time; a high load factor indicates a more steady rate of usage. Since industries generally have higher load factors than residential or general service customers, they are less costly to serve on a per-kilowatthour basis. Again, we can say that "a kilowatthour is a kilowatthour" as to energy content, but there may be a big difference in how much generating plant investment is required to convert the raw fuel into electric energy.

Figure 3

DEMAND VS. ENERGY

CUSTOMER A

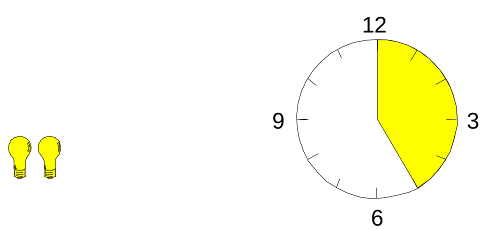


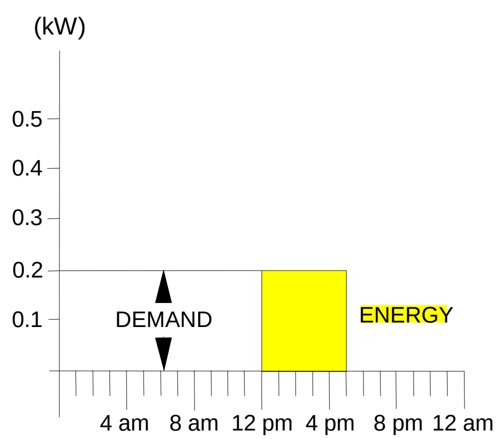


ENERGY: 500 watts x 2 hours = 1,000 watthours = 1.0 kWh

DEMAND: 500 watts = 0.5 kW

CUSTOMER B





ENERGY: 200 watts x 5 hours = 1,000 watthours = 1.0 kWh

DEMAND: 200 watts = 0.2 kW

Allocation

Q WHAT IS ALLOCATION?

A The final step in the cost of service analysis is the **allocation** of the costs to the customer classes. Demand, energy and customer allocation factors are developed to apportion the costs among the customer classes. Each factor measures the customer class's contribution to the system total cost.

For example, we have already determined that the amount of fuel expense on the system is a function of the energy required by customers. In order to allocate this expense among classes, we must determine how much each class contributes to the total kWh consumption and we must recognize the line losses associated with transporting and distributing the kWh. These contributions, expressed in percentage terms, are then multiplied by the expense to determine how much expense should be attributed to each class. An illustrative calculation, using L&P data, is shown in Table 1.

TABLE 1

Energy Allocation Factor

Rate Class	Energy Generated (MWh) (1)	Allocation Factor (2)
Residential	769,706	39.75%
Small GS	111,349	5.75%
Large GS	394,983	20.40%
Large Power	660,189	34.10%
Total	1,936,227	100.00%

For demand-related costs, we construct an allocation factor by looking at the important class demands. For purposes of discussion, Table 2 shows the calculation of this factor for L&P. (The selection and derivation of this factor is discussed in more detail beginning at page 18.)

Q DO THE RELATIONSHIPS BETWEEN THE ENERGY ALLOCATION FACTORS AND THE DEMAND ALLOCATION FACTORS TELL US ANYTHING ABOUT CLASS LOAD FACTOR?

A Yes. Recall that load factor is a measure of the consistency or uniformity of use of demand. Accordingly, customer classes' whose energy allocation factor is a larger percentage than their demand allocation have an above-average load factor, while customers whose demand allocation factor is higher than their energy allocation factor have a below-average load factor.

These relationships are merely the result of differences in how electricity is used. In the case of L&P (as is true for essentially every other utility) the large GS and large power classes have above-average load factors, while the residential and small GS customers have below-average load factors.

TABLE 2

Demand Allocation Factor
Production System

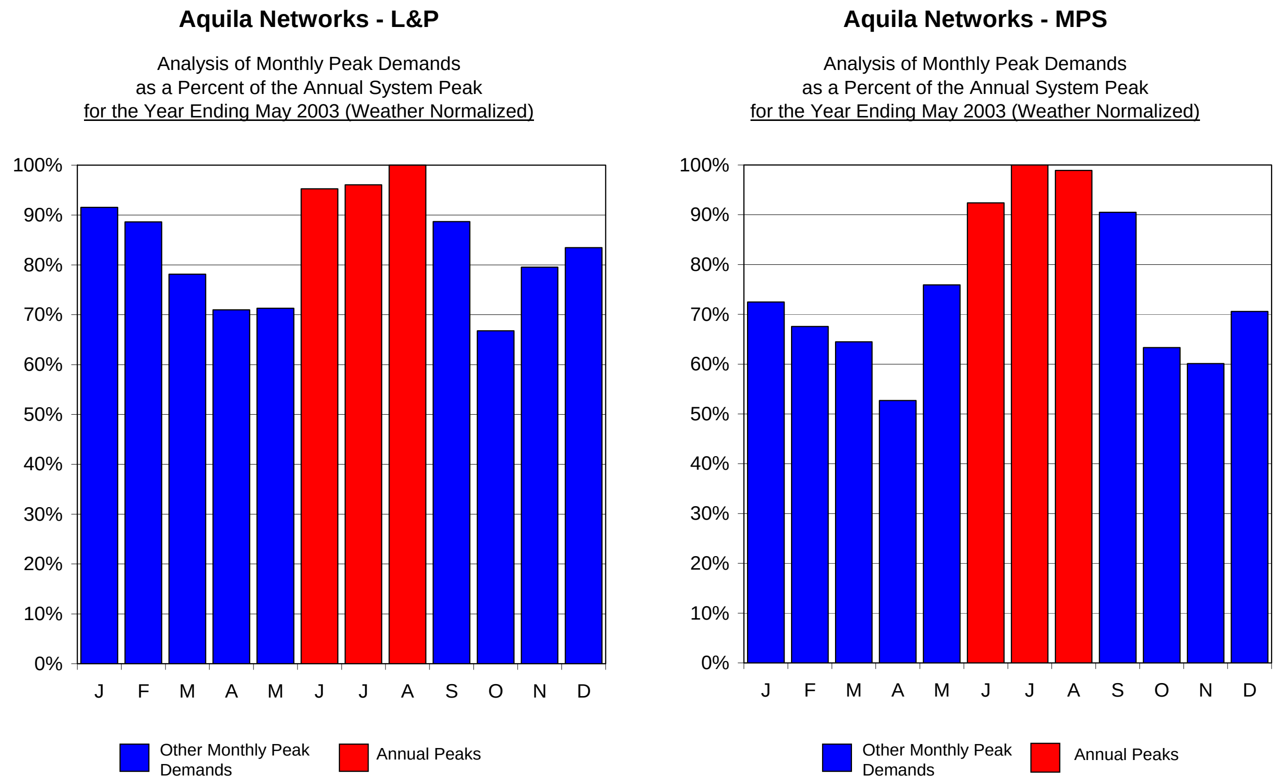
Rate Class	Production A&E (MW) (1)	Allocation Factor (2)
Residential	169.5	46.39%
Small GS	24.1	6.61%
Large GS	72.8	19.92%
Large Power	98.9	27.08%
Total	365.3	100.00%

Utility System Characteristics

Q WHAT IS THE IMPORTANCE OF UTILITY SYSTEM LOAD CHARACTERISTICS?

A Utility system load characteristics are an important factor in determining the specific method which should be employed to allocate fixed, or demand-related costs on a utility system. The most important characteristic is the annual load pattern of the utility. These characteristics for L&P and MPS are shown on Schedule 1, pages 1 and 2, respectively. For convenience, they are also shown here as Figure 4.

Figure 4



This shows the monthly system peak demands for the test year used in the study. The red bars show the months in which the highest peaks occurred. Although L&P has some fairly high loads in some winter months, the summer loads are more critical than the winter loads because in the winter generating units are capable of achieving higher output because of the cooler ambient (atmospheric and cooling water) temperatures. At lower ambient temperatures, generating units can produce a higher kW output. In addition, since the Midwest and southern region as a whole peaks in the summer, short-term power for covering peak demand periods is generally both more available and less expensive during the winter than is the case during the summer.

This analysis clearly shows that summer peaks dominate MPS and L&P systems. (This same information is presented in tabular form on Schedule 2.)

Q WHAT CRITERIA SHOULD BE USED TO DETERMINE AN APPROPRIATE METHOD FOR ALLOCATING PRODUCTION AND TRANSMISSION CAPACITY COSTS AMONG THE VARIOUS CUSTOMER CLASSES?

A The specific allocation method should be consistent with the principle of cost-causation; that is, the allocation should reflect the contribution of each customer class to the demands that caused the utility to incur capacity costs.

Q WHAT FACTORS CAUSE ELECTRIC UTILITIES TO INCUR PRODUCTION AND TRANSMISSION CAPACITY COSTS?

A As discussed previously, production and transmission plant must be sized to meet the maximum demand imposed on these facilities. Thus, an appropriate allocation method should accurately reflect the characteristics of the loads served by the utility. For example, if a utility has a high summer peak relative to the demands in other seasons, then production and transmission capacity costs should be allocated relative to each customer class' contribution to the summer peak demands. If a utility has predominant peaks in both the summer and winter periods, then an appropriate allocation method would be based on the demands imposed during both the summer and winter peak periods. For a utility with a very high load factor and/or a non-seasonal load pattern, then demands in all months may be important.

Q WHAT DO THESE CONSIDERATIONS MEAN IN THE CONTEXT OF THE AQUILA SYSTEM?

A As noted, the load patterns of both MPS and L&P have predominant summer peaks. This means that these demands should be the primary ones used in the allocation of generation and transmission cost. Demands in other months are of much less significance, do not compel the addition of generation capacity to serve them, and should not be used in determining the allocation of costs.

Q WHAT SPECIFIC RECOMMENDATIONS DO YOU HAVE?

A The two most predominantly used allocation methods in the industry are the coincident peak method and the average and excess demand method (A&E).

The coincident method utilizes the demands of customer classes coincident with the peaks selected for allocation. In the case of MPS and L&P, this would be the months of June, July and August.

Q WHAT IS THE A&E METHOD?

A The A&E method is one of a family of methods which incorporates a consideration of both the maximum rate of use and the duration of use. As the name implies, A&E makes a conceptual split of the system into an “average” component and an “excess” component. The “average” demand is simply the total kWh usage divided by the total number of hours in the year. This is the amount of capacity that would be required to produce the energy if it were taken at the same demand rate each hour. The system "excess" demand is the difference between the system peak demand and the system average demand.

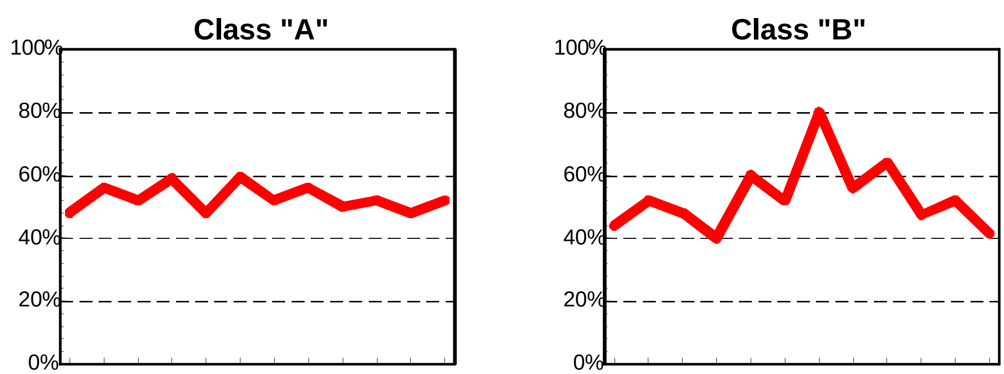
Under the A&E method, the average demand is allocated to classes in proportion to their average demand (energy usage) and the difference between the system average demand and the system peak(s) is then allocated to customer classes on the basis of a measure that represents their "peaking" or variability in usage.[1]

Q WHAT DO YOU MEAN BY VARIABILITY IN USAGE?

A As an example, Figure 5 shows two classes that have different monthly usage patterns.

Figure 5

<u>Load Patterns</u>



Both classes use the same total amount of energy and, therefore, have the same average demand. Class B, though, has much greater maximum demand than the Class A. The greater maximum demand imposes greater costs on the utility system. This is because the utility must provide sufficient capacity to meet the projected

[1]NARUC Electric Utility Cost Allocation Manual, 1992, page 81.

maximum demands of its customers. There may also be higher costs due to the greater variability of usage of some classes. This variability requires that a utility cycle its generating units in order to match output with demand on a real time basis. The stress of cycling generating units up and down causes wear and tear on the equipment, resulting in higher maintenance cost.

Thus, the excess component of the A&E method is an attempt to allocate the additional capacity requirements of the system (measured by the system excess) in proportion to the "peakiness" of the customer classes (measured by the class excess demands).

Q WHAT DEMAND ALLOCATION METHODOLOGY DO YOU RECOMMEND FOR USE ON THE MPS AND L&P SYSTEMS?

A First, in order to reflect cost causation the methodology must give predominant weight to loads occurring during the summer months. Loads during these months (the peak loads) are the primary driver which has and continues to cause the utility to expand its generation and transmission capacity, and therefore should be given predominant weight in the allocation of capacity costs.

Either a coincident peak study, using the demands during the peak summer months, or a version of an average and excess cost of service study that uses peak loads occurring during the summer, would be most appropriate to reflect these characteristics. The results should be similar as long as only summer period peak loads are used. I will make my recommendations based on the A&E method. It considers the maximum class demands during the critical time periods, and is less susceptible to variations in the absolute hour in which peaks occur – producing a somewhat more stable result over time.

Schedule 3 shows the derivation of the demand allocation factor for generation using class non-coincident peaks from the three summer peak months.

Q REFERRING TO PAGE 1 OF SCHEDULE 3, WHICH PERTAINS TO L&P, PLEASE EXPLAIN THE DEVELOPMENT OF THE A&E ALLOCATION FACTOR.

A Column 1 shows the average of the non-coincident peaks for each class in the three summer months. As explained previously, the summer months are selected because of their criticality in determining the need for generation capacity or firm purchase power. Column 2 shows the amount of energy required by each class. Column 3 is the average demand, in kilowatts, which is determined by dividing the annual energy in column 2 by the number of hours in a year. Column 4 shows the percentage relationship between the average demand for each class and the total system.

The excess demand, shown in column 5, is equal to the non-coincident peak demand shown in column 1 minus the average demand that is shown in column 3. Column 6 shows the excess demand percentage, which is a relationship among the excess demand of each customer class and the total system's excess demand.

Finally, column 7 presents the composite A&E allocation factor. It is determined by weighting the average demand responsibility of each class (which is the same as each class' energy allocation factor) by the system load factor, and weighting the excess demand factor by the quantity one minus the system load factor.

Making the Cost of Service Study–Summary

Q PLEASE SUMMARIZE THE PROCESS AND THE RESULTS OF A COST OF SERVICE ANALYSIS.

A As previously discussed, the cost of service procedure involves three steps:

1. Functionalization–Identify the different functional "levels" of the system;
2. Classification–Determine, for each functional type, the primary cause or causes (customer, demand or energy) of that cost being incurred; and
3. Allocation–Calculate the class proportional responsibilities for each type of cost and spread the cost among classes.

Q WHERE ARE YOUR COST OF SERVICE RESULTS PRESENTED?

A Results for L&P are presented in Schedule 4 and results for MPS are presented in Schedule 5.

Q REFERRING TO SCHEDULE 4, PLEASE EXPLAIN THE ORGANIZATION AND WHAT IS SHOWN.

A Cost of service results are generally shown in one of two formats. Namely, a rate of return format or a total cost of service format.

Q WHAT ARE THESE FORMATS?

A Please refer to page 1 of Schedule 4. It shows the rate of return format. In this format, the class revenues and expenses are compared to determine the operating income, or return, produced from service under the rates currently in effect. This is shown on line 3. This return is then divided by the rate base allocated to each customer class to determine the current rate of return, which is shown on line 5.

Q PLEASE EXPLAIN THESE RESULTS.

A This cost study shows two things. First, it shows that at present rates not all classes are equally profitable. In other words, some classes pay a portion of the costs incurred to serve other customer classes. Second, it provides the information from which we can calculate the necessary increase (or decrease) in revenues from each class to achieve cost-based revenues (line 8). It is the difference between the required return and the earned return.

Q WHAT IS THE OTHER FORMAT?

A The other format is the functional cost format, and it is shown on page 2 of each of Schedules 4 and 5. In this format all costs are allocated by function and totaled to determine cost responsibility. The cost responsibility is compared to current revenues and the revenue deficiency, or excess, is then determined.

Q ARE THE RESULTS EQUIVALENT?

A Yes. The adjustment to move from existing revenues to cost of service is the same under either approach (within rounding tolerances), it is just two different ways of presenting cost of service results. At the end of the day, the required increases or decreases in revenues are the same regardless of presentation format.

Q WHAT ELSE IS SHOWN IN SCHEDULES 4 AND 5?

A Page 3 of each schedule shows the allocation methodology applied to each of the principal functional components of cost.

Based on the discussions at the technical conferences that the parties held, I believe there is little controversy about the classification and allocation of cost at the distribution level, and accordingly I will not spend time to explain in detail how all of these costs are allocated. Rather, the principal point of difference among the parties is in the allocation of production and transmission plant, and that is where I have focused most of my testimony.

Q THE RATES, WHEN EXPRESSED PER KILOWATTHOUR, CHARGED TO LARGE GS AND LARGE POWER CUSTOMERS ARE CURRENTLY LESS THAN THE RATES CHARGED TO RESIDENTIAL AND SMALL GS CUSTOMERS. DOES THE COST OF SERVICE STUDY INDICATE THAT THIS IS APPROPRIATE?

A Yes. Table 3 shows the cost-based revenue requirement for each L&P class. Note that the cost, per unit, to serve the large GS and large power customers is significantly less than the cost to serve the residential and small GS customers. Similar relationships hold on the MPS system, and in fact on any electric utility system.

TABLE 3

Class Revenue Requirement
Average and Excess Method
(Dollars in Thousands)

Rate Class	Cost-Based Revenue (1)	Energy Sales (MWh) (2)	Cost per kWh (3)
Residential	$46,095	714,107	6.45¢
Small GS	6,664	103,306	6.45¢
Large GS	15,479	366,482	4.22¢
Large Power	21,083	614,155	3.43¢
Total	$89,321	1,798,050	4.97¢

As previously discussed, the reasons for these differences are: (1) load factor, (2) delivery voltage, and (3) size.

The large GS and large power customers have higher load factors, as shown in Table 4 for L&P. Consequently, the capital costs related to production and transmission are spread over a greater number of kilowatthours than is the case for lower load factor classes, resulting in lower costs per kWh and hence lower rates.

TABLE 4

Comparative Load Factors

Rate Classes	**Energy Generated (MWh)** (1)	**Generation Average & Excess Demand (MW)** (2)	**Load Factor** (3)
Residential	769,706	169.5	52%
Small GS	111,349	24.1	53%
Large GS	394,983	72.8	62%
Large Power	660,189	98.9	76%
Total Retail	1,936,227	365.3	61%

In addition, these customers take service at a higher voltage level. This means that they do not cause the costs associated with lower voltage distribution. Losses incurred in providing service also are lower. Table 5 lists voltage level and composite loss percentages for the various classes. Losses are 7.8% at the secondary level and 5.9% at the primary level (for any customer served at the transmission level, the loss percentage would still be lower).

TABLE 5

Energy Loss Factors

Rate Classes	Percent of Sale by Voltage Level		Composite Loss Percentage
	Secondary[1]	Primary[2]	
	(1)	(2)	(3)
Residential	100%	0%	7.79%
Small GS	100%	0%	7.79%
Large GS	100%	0%	7.79%
Large Power	85%	15%	7.49%

[1]Loss factor is 7.79%
[2]Loss factor is 5.87%

The per capita sales to these classes are also much greater than to the other classes, as shown in Table 6. L&P sells 338,000 and 10,800,000 kilowatthours per large GS and large power customer, respectively, but only 13,000 kilowatthours per residential customer, or between 25 and 830 times more per capita, as shown in Table 6. The customer-related costs to serve the former are not 25 to 830 times the customer-related costs to serve the residential customer.

TABLE 6

Energy Sold Per Customer

Rate Classes	Energy Sold (MWh)	Number of Customers	KWh Sold per Customer
	(1)	(2)	(3)
Residential	714,107	56,048	13,000
Small GS	103,306	5,972	17,000
Large GS	366,482	1,084	338,000
Large Power	614,155	57	10,800,000
Total Retail	1,798,050	63,161	28,000

These differences in the service and usage characteristics–load factor, delivery voltage and size–result in a lower per unit cost to serve customers operating at a higher load factor, taking service at higher delivery voltage and purchasing a larger quantity of power and energy at a single delivery point.

Adjustment of Class Revenues

Q WHAT SHOULD BE THE PRIMARY BASIS FOR ESTABLISHING CLASS REVENUE REQUIREMENTS AND DESIGNING RATES?

A Cost should be the primary factor used in both steps.

Just as cost of service is used to establish a utility's total revenue requirement, it should also be the basis used to establish the revenues collected from each customer class and to design rate schedules.

Although factors such as simplicity, gradualism and ease of administration may also be taken into account, the basic starting point and guideline throughout the process should be cost of service. To the extent practicable, rate schedules should be structured and designed to reflect the important cost-causative features of the service provided, and to collect the appropriate cost from the customers within each class or rate schedule, based upon the individual load patterns exhibited by those customers.

Q WHAT IS THE BASIS FOR YOUR RECOMMENDATION THAT COST BE USED AS THE PRIMARY FACTOR FOR THESE PURPOSES?

A The basic reasons for using cost as the primary factor are equity, conservation, and engineering efficiency (cost-minimization).

Q PLEASE EXPLAIN HOW EQUITY IS ACHIEVED BY BASING RATES ON COST.

A When rates are based on cost, each customer pays what it costs the utility to provide service to that customer; no more and no less. If rates are based on other than cost factors, then some customers will pay the costs attributable to providing service to other customers–which is inherently inequitable.

Q HOW DO COST-BASED RATES FURTHER THE GOAL OF CONSERVATION?

A Conservation occurs when wasteful, inefficient use is discouraged or minimized. Only when rates are based on costs do customers receive a balanced price signal upon which to make their electric consumption decisions. If rates are not based on costs, then customers who are not paying their full costs may be mislead into using electricity inefficiently in response to the distorted rate design signals they receive.

Q WILL COST-BASED RATES ASSIST IN THE DEVELOPMENT OF COST-EFFECTIVE DEMAND-SIDE MANAGEMENT (DSM) PROGRAMS?

A Yes. The success of DSM (both energy efficiency and demand response programs) depends, to a large extent, on customer receptivity. There are many actions that can be taken by consumers to reduce their electricity requirements. A major element in a customer's decision-making process is the amount of reduction that can be achieved in the electric bill as a result of DSM activities. If the bill received by a customer is subsidized by other customers; that is, the bill is based on rates which are below cost, that customer will have less reason to engage in DSM activities than when the bill reflects the actual cost of the electric service provided.

For example, assume that the relevant cost to produce and deliver energy is 10 cents per kWh. If a customer has an opportunity to install energy efficiency or

DSM equipment that would allow the customer to reduce energy use or demand, the customer will be much more likely to make that investment if the price he pays for electricity equals the cost of electricity, i.e., 10 cents per kWh, rather than if the customer is receiving a subsidized rate of 8 cents per kWh.

Q HOW DO COST-BASED RATES ACHIEVE THE COST-MINIMIZATION OBJECTIVE?

A When the rates are designed so that the energy costs, demand costs, and customer costs are properly reflected in the energy, demand and customer components of the rate schedules, respectively, customers are provided with the proper incentives to minimize their costs, which will in turn minimize the costs to the utility.

If a utility attempts to extract a disproportionate share of revenues from a class that has alternatives available (such as producing products at other locations where costs are lower), then the utility will be faced with the situation where it must discount the rates or lose the load, either in part or in total. To the extent that the load could have been served more economically by the utility, then either the other customers of the utility or the stockholders (or some combination of both) will be worse off than if the rates were properly designed on the basis of cost.

From a rate design perspective, overpricing the energy portion of the rate and underpricing the fixed components of the rate (such as customer and demand charges) will result in a disproportionate share of revenues being collected from large customers and high load factor customers. To the extent that these customers may have lower cost alternatives than do the smaller or the low load factor customers, the same problems noted above are created.

Q HAVE YOU PREPARED RECOMMENDATIONS FOR THE ALLOCATION OF REVENUE ADJUSTMENTS (INCREASES OR DECREASES) AMONG CUSTOMER CLASSES?

A Yes, I have. This appears on Schedule 6.

Q PLEASE EXPLAIN SCHEDULE 6.

A Schedule 6 shows, in column 1, the rate schedule revenues under present rates. Column 2 shows the required percentage increases or decreases (as determined in the cost of service study) to fully align rates with costs.

Q YOU HAVE EXPRESSED WHY COST OF SERVICE SHOULD BE THE GOAL IN RATE DESIGN. IS IT ALWAYS POSSIBLE TO MOVE RATES EXACTLY TO COST OF SERVICE RESULTS, REGARDLESS OF THE LEVEL OF INCREASES WHICH MAY BE REQUIRED?

A No. It is more customary to move toward class cost of service results in a manner that recognizes the impacts of higher rates. In the case of L&P, the residential class would require an increase of 12% to move to cost. This is generally higher than would normally be imposed in a single step as a result strictly of inter-class rate realignments.

Q WHAT IS YOUR RECOMMENDATION?

A I recommend that the increase to any customer class be capped at between 4% and 6%. Doing so would allow for a reasonable movement toward cost of service without being overly disruptive.

Q HOW SHOULD THESE ADJUSTMENTS BE IMPLEMENTED IN RATES?

A There is pending a general rate proceeding for Aquila L&P and Aquila MPS in MPSC Case No. ER-2005-0436. My recommendation is to transfer the percentage adjustments determined in this case to the pending general rate proceeding and implement these adjustments in concert with the overall change in revenues that L&P and MPS may receive as a result of that proceeding. Thus, if the overall increase granted in the general rate proceeding is "x," then I would recommend that the residential class increase be set as "x" plus the inter-class revenue adjustment. Decreases for other classes should be established at "x" minus their corresponding downward adjustment.

Q PLEASE GIVE AN EXAMPLE.

A For purposes of illustration, assume that Aquila receives an 8% increase in MPSC Case No. ER-2005-0436. Then, the increase to the classes that have below average rates of return, as shown in Schedule 6, would be 8% plus 6%, or 14%. Customer classes with rates of return in excess of the average would receive an increase equal to 8% minus the adjustments specified on Schedule 6. Taking the LP class as an example, for L&P, the increase would be 8% - 3.9%, or an increase of 4.1%. For MPS, the increase would be 8% - 5%, or an increase of 3%.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Appendix A

<u>Qualifications of Maurice Brubaker</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and President of the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I was graduated from the University of Missouri in 1965, with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation I was employed by the Utilities Section of the Engineering and Technology Division of Esso Research and Engineering Corporation of Morristown, New Jersey, a subsidiary of Standard Oil of New Jersey.

In the Fall of 1965, I enrolled in the Graduate School of Business at Washington University in St. Louis, Missouri. I was graduated in June of 1967 with the Degree of Master of Business Administration. My major field was finance.

From March of 1966 until March of 1970, I was employed by Emerson Electric Company in St. Louis. During this time I pursued the Degree of Master of Science in Engineering at Washington University, which I received in June, 1970.

In March of 1970, I joined the firm of Drazen Associates, Inc., of St. Louis, Missouri. Since that time I have been engaged in the preparation of numerous studies relating to electric, gas, and water utilities. These studies have included analyses of the cost to serve various types of customers, the design of rates for utility services, cost forecasts, cogeneration rates and determinations of rate base and operating income. I have also addressed utility resource planning principles and plans, reviewed capacity additions to determine whether or not they were used and useful, addressed demand-side management issues independently and as part of least cost planning, and have reviewed utility determinations of the need for capacity additions and/or purchased power to determine the consistency of such plans with least cost planning principles. I have also testified about the prudency of the actions undertaken by utilities to meet the needs of their customers in the wholesale power markets and have recommended disallowances of costs where such actions were deemed imprudent.

I have testified before the Federal Energy Regulatory Commission (FERC), various courts and legislatures, and the state regulatory commissions of Alabama, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Guam, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Missouri, Nevada, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Texas, Utah, Virginia, West Virginia, Wisconsin and Wyoming.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and assumed the utility rate and economic consulting activities of Drazen Associates, Inc., founded in 1937. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff. Our staff includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business.

During the past ten years, Brubaker & Associates, Inc. and its predecessor firm has participated in over 700 major utility rate and other cases and statewide generic investigations before utility regulatory commissions in 40 states, involving electric, gas, water, and steam rates and other issues. Cases in which the firm has been involved have included more than 80 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

An increasing portion of the firm's activities is concentrated in the areas of competitive procurement. While the firm has always assisted its clients in negotiating contracts for utility services in the regulated environment, increasingly there are opportunities for certain customers to acquire power on a competitive basis from a supplier other than its traditional electric utility. The firm assists clients in identifying and evaluating purchased power options, conducts RFPs and negotiates with suppliers for the acquisition and delivery of supplies. We have prepared option studies and/or conducted RFPs for competitive acquisition of power supply for industrial and other end-use customers throughout the Unites States and in Canada, involving total needs in excess of 3,000 megawatts. The firm is also an associate member of the Electric Reliability Council of Texas and a licensed electricity aggregator in the State of Texas.

In addition to our main office in St. Louis, the firm has branch offices in Phoenix, Arizona; Chicago, Illinois; Corpus Christi, Texas; and Plano, Texas.

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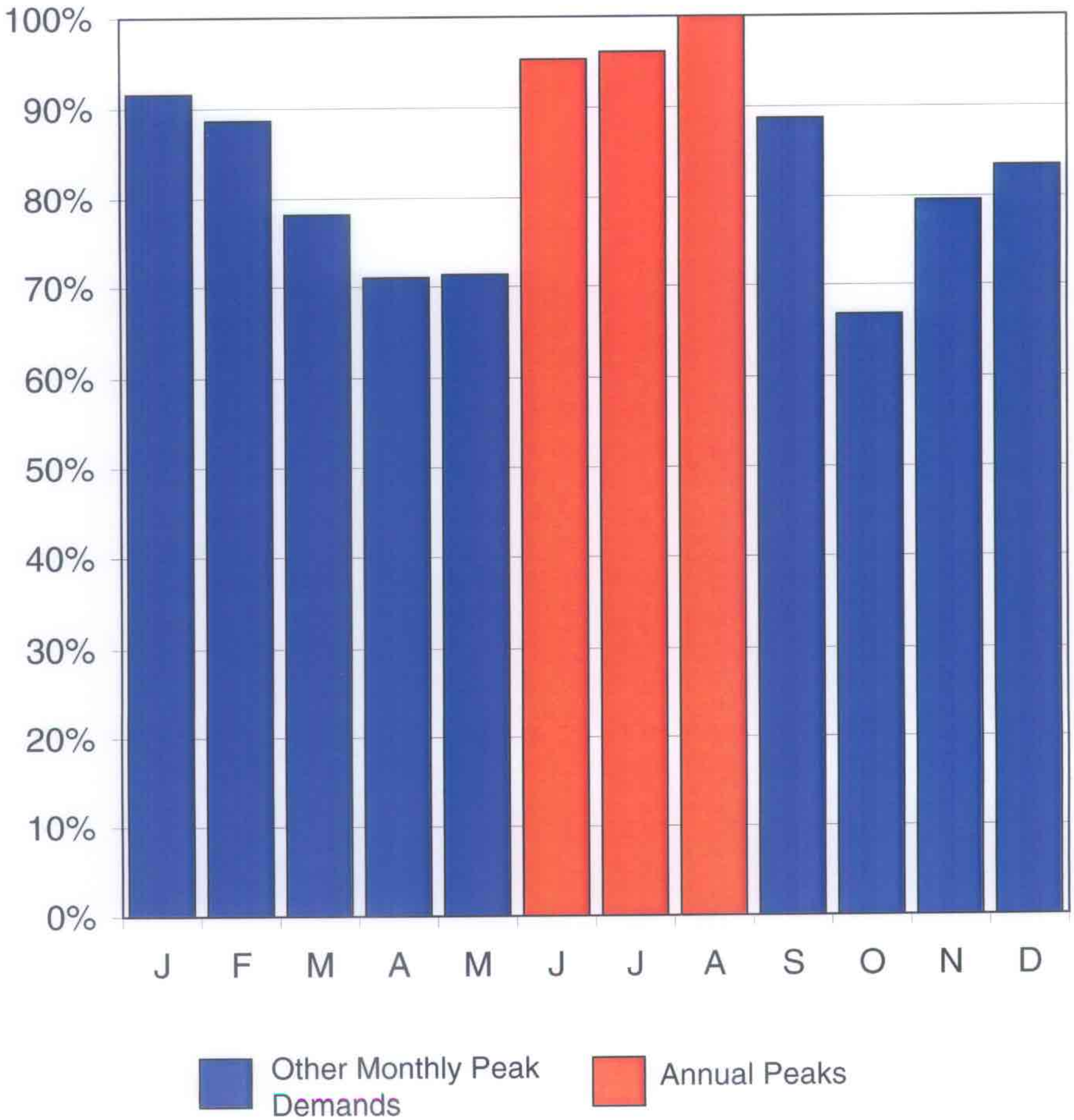
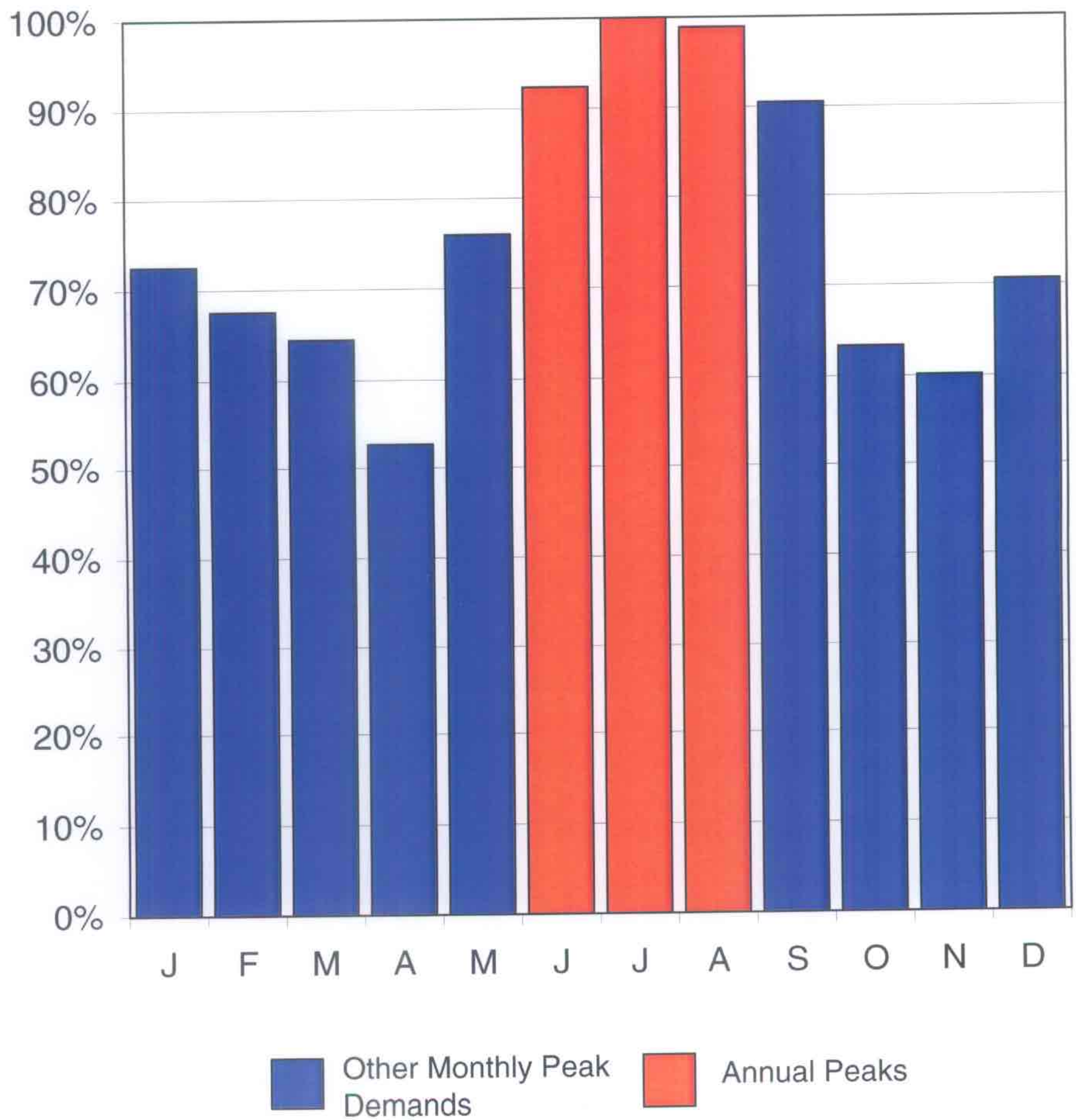
Aquila Networks - L&P

Analysis of Monthly Peak Demands
as a Percent of the Annual System Peak
for the Year Ending May 2003 (Weather Normalized)



Aquila Networks - MPS

Analysis of Monthly Peak Demands
as a Percent of the Annual System Peak
for the Year Ending May 2003 (Weather Normalized)



Aquila Networks - L&P

Analysis of Monthly Peak Demands
as a Percent of the Annual System Peak
for the Year Ending May 2003 (Weather Normalized)

Line	Month	MW (1)	Percent (2)
1	January	348	92
2	February	337	89
3	March	297	78
4	April	270	71
5	May	271	71
6	June	363	95
7	July	366	96
8	August	381	100
9	September	337	89
10	October	254	67
11	November	303	80
12	December	318	83

Aquila Networks - MPS

Analysis of Monthly Peak Demands
as a Percent of the Annual System Peak
for the Year Ending May 2003 (Weather Normalized)

Line	Month	MW (1)	Percent (2)
1	January	912	73
2	February	850	68
3	March	812	64
4	April	663	53
5	May	955	76
6	June	1,163	92
7	July	1,259	100
8	August	1,245	99
9	September	1,139	91
10	October	797	63
11	November	757	60
12	December	888	71

AQUILA NETWORKS - L&P

Development of 3 NCP
Average and Excess Demand Allocators
For Production & Transmission

System Load Factor:	
Load Factor	60.51%
1 - LF	39.49%

Line	Rate Classes	Class Non-Coincident 3 Summer NCP (kW)	Energy in kWh	Average Demand (kW)	Average Demand Percent	Excess Demand (kW)	Excess Demand Percent	Average & Excess Allocator
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	RES	195,687	769,706,042	87,866	39.75%	107,821	56.56%	46.39%
2	SGS	27,805	111,349,188	12,711	5.75%	15,094	7.92%	6.61%
3	LGS	81,684	394,982,693	45,089	20.40%	36,595	19.20%	19.92%
4	LPS	106,493	660,188,838	75,364	34.10%	31,129	16.33%	27.08%
5	Total	411,668	1,936,226,761	221,030	100.00%	190,638	100.00%	100.00%

Note:
Column (3) = Column (2) / 8760
Column (5) = Column (1) - Column (3)
Column (7) = Column (4) * LF + Column (6) * (1-LF)

RES Class = sum of Rate Classes RES-GEN, RES-H2O & RES-HEAT
SGS Class = sum of Rate Class SGS
LGS Class = sum of Rate Classes LGS-S & LGS-P
LPS Class = sum of Rate Classes LPS-S & LPS-P

AQUILA NETWORKS - MPS

Development of 3 NCP
Average and Excess Demand Allocators
For Production & Transmission

System Load Factor:

Load Factor	51.01%
1 - LF	48.99%

Line	Rate Classes	Class Non-Coincident 3 Summer NCP (kW)	Energy in kWh	Average Demand (kW)	Average Demand Percent	Excess Demand (kW)	Excess Demand Percent	Average & Excess Allocator
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	RES	744,799	2,494,774,685	284,792	46.12%	460,007	62.87%	54.33%
2	SGS	222,061	836,648,622	95,508	15.47%	126,553	17.30%	16.36%
3	LGS	175,495	851,216,974	97,171	15.74%	78,324	10.70%	13.27%
4	LPS	205,329	1,220,073,678	139,278	22.56%	66,051	9.03%	15.93%
5	SC	1,489	6,297,491	719	0.12%	770	0.11%	0.11%
6	Total	1,349,174	5,409,011,450	617,468	100.00%	731,706	100.00%	100.00%

Note:
Column (3) = Column (2) / 8760
Column (5) = Column (1) - Column (3)
Column (7) = Column (4) * LF + Column (6) * (1-LF)

RES Class = sum of Rate Classes RES-GEN & RES-SH
SGS Class = sum of Rate Classes SGS-S, SGS-P, S&C, & MUNI-WPR
LGS Class = sum of Rate Classes LGS-S, LGS-P, & LGS-SF
LPS Class = sum of Rate Classes LPS-S & LPS-P
SC Class = sum of Rate Class MODINE

BAI COST-OF-SERVICE RESULTS - A&E SUMMER NCP
RATE OF RETURN FORMAT ($000)
AQUILA NETWORKS - L&P
CASE NO. EO-2002-384

Line	Description	Residential	SGS	LGS	LP	TOTAL
		(1)	(2)	(3)	(4)	(5)
1	Revenue [1]	$ 44,688	$ 8,120	$ 19,222	$ 24,855	$ 96,885
2	Expense	41,455	5,925	14,519	20,065	81,964
3	Return	3,233	2,195	4,703	4,790	14,921
4	Rate Base	$ 95,756	$ 14,936	$ 28,597	$ 34,576	$ 173,865
5	Rate of Return	3.38%	14.70%	16.44%	13.85%	8.58%
6	Allowed Rate of Return	8.58%				
7	Return at Cost of Service [2]	$ 8,218	$ 1,282	$ 2,454	$ 2,967	$ 14,921
8	Required Increase or (Decrease)	$ 4,985	$ (913)	$ (2,249)	$ (1,823)	$ -
9	Required Increase or (Decrease) Adjusted For Roundin(	$ 4,989	$ (912)	$ (2,250)	$ (1,827)	$ -

Notes:

[1] Rate Revenue plus allocated other revenue.

[2] Revenue Neutral Rate of Return times Rate Base

BAI COST-OF-SERVICE RESULTS - A&E SUMMER NCP

FUNCTIONAL COST FORMAT - AQUILA NETWORKS - L&P

CASE NO. EO-2002-384

FUNCTIONAL CATEGORY			RES	SGS	LGS	LP		Other	TOTAL
PRODUCTION	CAPACITY		$15,631,185	$2,226,111	$6,713,490	$9,124,514	$0	$0	$33,695,300
PRODUCTION	ENERGY		$10,218,001	$1,478,183	$5,243,474	$8,764,138	$0	$0	$25,703,796
TRANSMISSION	CAPACITY		$3,495,329	$497,786	$1,501,221	$2,040,356	$0	$0	$7,534,692
DISTRIBUTION	SUBSTATIONS	DEMAND	$2,301,661	$329,408	$949,987	$1,233,605	$0	$0	$4,814,661
DISTRIBUTION	POLES AND CONDUCTORS	PRI. FEEDER - DEMAND	$0	$0	$0	$0	$0	$0	$0
DISTRIBUTION	POLES AND CONDUCTORS	PRI. TAP -CUSTOMER	$1,396,799	$254,497	$115,351	$7,273	$0	$0	$1,773,920
DISTRIBUTION	POLES AND CONDUCTORS	SEC. CUSTOMER	$1,380,039	$251,443	$113,442	$6,681	$0	$0	$1,751,605
DISTRIBUTION	POLES AND CONDUCTORS	PRI. TAP - DEMAND	$2,855,321	$408,647	$1,178,504	$1,530,346	$0	$0	$5,972,817
DISTRIBUTION	POLES AND CONDUCTORS	SEC. DEMAND	$779,514	$84,801	$243,236	$269,328	$0	$0	$1,376,879
DISTRIBUTION	TRANSFORMERS	SEC. CUSTOMER	$2,707,237	$493,258	$222,540	$13,107	$0	$0	$3,436,142
DISTRIBUTION	TRANSFORMERS	DEMAND	$0	$0	$0	$0	$0	$0	$0
DISTRIBUTION	CUSTOMER INSTALLATIONS		$302,614	$55,136	$24,875	$1,465	$0	$0	$384,091
DISTRIBUTION	SERVICES		$1,329,024	$242,148	$109,754	$6,920	$0	$0	$1,687,846
DISTRIBUTION	METERS		$1,086,523	$197,964	$89,728	$5,657	$0	$0	$1,379,873
	CUSTOMER DEPOSITS		($32,584)	($3,472)	($630)	($33)	$0	$0	($36,719)
	METER READING		$380,618	$69,349	$31,433	$1,982	$0	$0	$483,381
	BILLING, SALES, SERVICE		$3,062,984	$326,360	$59,239	$3,115	$0	$0	$3,451,697
	ASSIGNED LGS/LPS/SC		$0	$0	$376,216	$19,783	$0	$0	$395,998
	ASSIGNED RES/SGS		$2,782,228	$296,445	$0	$0	$0	$0	$3,078,673
	EXCESS FACILITY		$0	$0	$0	$0	$0	$0	$0
	TOTAL		$49,676,494	$7,208,065	$16,971,858	$23,028,236	$0	$0	$96,884,654
	Allocate Cost of Service for Others		$0	$0	$0	$0	$0	$0	$0
	TOTAL COST OF SERVICE		$49,676,494	$7,208,065	$16,971,858	$23,028,236	$0	$0	$96,884,654
	%		51.27%	7.44%	17.52%	23.77%	0.00%	0.00%	100%
	RATE REVENUE		$41,106,120	$7,575,521	$17,728,841	$22,910,401	$0	$2,238,976	$91,559,859
	Allocate Rate Revenues for Others		$1,148,009	$166,576	$392,215	$532,176	$0	($2,238,976)	$0
	NON RATE REVENUE		$746,413	$137,558	$382,853	$442,966	$0	$40,656	$1,750,446
	Interruptible Credit		$0	$0	($4,927)	($12,317)	$0	$0	($17,244)
	OffSystem Revenue		$1,666,133	$237,282	$715,593	$972,585	$0	$0	$3,591,593
	Excess Facility Revenue		$0	$0	$0	$0	$0	$0	$0
	Sale of Emission		$0	$0	$0	$0	$0	$0	$0
	Allocate Non Rate Rev for Others		$20,846	$3,025	$7,122	$9,663	$0	($40,656)	$0
	TOTAL REVENUE		$44,687,522	$8,119,962	$19,221,697	$24,855,474	$0	$0	$96,884,654
	%		46.12%	8.38%	19.84%	25.65%	0.00%	0.00%	100%
	REVENUE DEFICIENCY		$4,988,972	($911,896)	($2,249,838)	($1,827,237)	$0	$0	$0
	% CHANGE		12.14%	-12.04%	-12.69%	-7.98%		0.00%	0.00%

AQUILA NETWORKS - L&P

Cost-of-Service Allocation Methods

Line	Functionalization Category	Allocation Method
1	**Production:**	
2	Capacity	A&E Summer NCP
3	Energy	Total Year Sales
4	**Transmission:**	A&E Summer NCP
5	**Distribution:**	
6	Substations	Class Peak at Primary Voltage Level
7	Feeder Lines	Class Peak at Primary Voltage Level
8	OH Lines & Poles - Primary	All Customers - Weighted Customers
9	OH Lines & Poles - Secondary	Secondary Customers - Weighted Customers
10	Poles & Conductors - Primary	Class Peak at Primary Voltage Level
11	Poles & Conductors - Secondary	Class Peak at Secondary Voltage Level
12	UG Conduits and Conductors - Primary	All Customers - Weighted Customers
13	UG Conduits and Conductors - Secondary	Secondary Customers - Weighted Customers
14	Transformers - Sec Cust	Secondary Customers - Weighted Transformers
15	Transformers - Sec Demand	Secondary Customers - Weighted Transformers
16	Customer Installations	Secondary Customers - Weighted Transformers
17	Services	All Customers - Weighted Services
18	Meters	All Customers - Weighted Meters
19	**Other:**	
20	Customer Deposit	All Customers
21	Meter Reading	All Customers - Weighted Customers
22	Billing & Sales	All Customers
23	Assigned - LGS/LPS/SC	All Customers - LGS/LPS
24	Assigned - RES/SGS	All Customers - RES/SGS

BAI COST-OF-SERVICE RESULTS - A&E SUMMER NCP
RATE OF RETURN FORMAT ($000)
AQUILA NETWORKS - MPS
CASE NO. EO-2002-384

Line	Description	Residential	SGS	LGS	LP	SC	TOTAL
		(1)	(2)	(3)	(4)	(5)	(6)
1	Revenue [1]	$ 183,394	$ 57,790	$ 47,358	$ 54,903	$ 281	$ 343,726
2	Expense	162,278	43,824	35,498	44,698	275	286,574
3	Return	21,115	13,966	11,860	10,205	6	57,152
4	Rate Base	$ 421,694	$ 100,921	$ 65,957	$ 74,131	$ 533	$ 663,236
5	Rate of Return	5.01%	13.84%	17.98%	13.77%	1.19%	8.62%
6	Allowed Rate of Return	8.62%					
7	Return at Cost of Service [2]	$ 36,338	$ 8,697	$ 5,684	$ 6,388	$ 46	$ 57,152
8	Required Increase or (Decrease)	$ 15,223	$ (5,269)	$ (6,177)	$ (3,817)	$ 40	$ -
9	Required Increase or (Decrease) Adjusted For Roundinç	$ 15,216	$ (5,269)	$ (6,174)	$ (3,812)	$ 40	$ -

Notes:

[1] Rate Revenue plus allocated other revenue.

[2] Revenue Neutral Rate of Return times Rate Base

BAI COST-OF-SERVICE RESULTS - A&E SUMMER NCP

FUNCTIONAL COST FORMAT - AQUILA NETWORKS - MPS

CASE NO. EO-2002-384

FUNCTIONAL CATEGORY			RES	SGS	LGS	LP	SC	Other	TOTAL
PRODUCTION	CAPACITY		$57,948,618	$17,454,324	$14,156,481	$16,990,556	$118,368	$0	$106,668,348
PRODUCTION	ENERGY		$47,644,607	$15,984,496	$16,278,827	$23,778,202	$124,464	$0	$103,810,596
TRANSMISSION	CAPACITY		$15,692,078	$4,726,508	$3,833,475	$4,600,923	$32,053	$0	$28,885,038
DISTRIBUTION	SUBSTATIONS	DEMAND	$6,034,966	$1,765,390	$1,382,390	$1,630,741	$12,116	$0	$10,825,603
DISTRIBUTION	POLES AND CONDUCTORS	PRI. FEED - DEMAND	$0	$0	$0	$0	$0	$0	$0
DISTRIBUTION	POLES AND CONDUCTORS	PRI. TAP-CUSTOMER	$7,469,441	$1,077,475	$149,093	$50,886	$0	$0	$8,746,895
DISTRIBUTION	POLES AND CONDUCTORS	SEC. CUSTOMER	$6,809,314	$982,030	$133,133	$35,282	$0	$0	$7,959,758
DISTRIBUTION	POLES AND CONDUCTORS	PRI. TAP - DEMAND	$11,428,373	$3,343,106	$2,617,823	$3,088,123	$22,945	$0	$20,500,370
DISTRIBUTION	POLES AND CONDUCTORS	SEC. DEMAND	$5,404,841	$1,392,329	$1,022,651	$613,685	$9,305	$0	$8,442,811
DISTRIBUTION	TRANSFORMERS	SEC. CUSTOMER	$13,508,801	$1,948,221	$264,118	$69,994	$0	$0	$15,791,134
DISTRIBUTION	TRANSFORMERS	DEMAND	$0	$0	$0	$0	$0	$0	$0
DISTRIBUTION	CUSTOMER INSTALLATIONS		$1,494,830	$215,582	$29,226	$7,745	$0	$0	$1,747,384
DISTRIBUTION	SERVICES		$6,253,422	$902,063	$124,821	$42,602	$173	$0	$7,323,081
DISTRIBUTION	METERS		$4,241,413	$611,828	$84,661	$28,895	$117	$0	$4,966,913
	CUSTOMER DEPOSITS		($274,442)	($39,589)	($1,592)	($211)	($1)	$0	($315,835)
	METER READING		$1,547,158	$223,179	$30,882	$10,540	$43	$0	$1,811,802
	BILLING, SALES, SERVICE		$6,006,829	$866,491	$34,854	$4,608	$32	$0	$6,912,815
	ASSIGNED LGS/LPS/SC		$0	$0	$1,043,299	$137,941	$971	$0	$1,182,211
	ASSIGNED RES/SGS		$7,399,689	$1,067,413	$0	$0	$0	$0	$8,467,102
			$0	$0	$0	$0	$0	$0	$0
	TOTAL		$198,609,939	$52,520,846	$41,184,145	$51,090,512	$320,588	$0	$343,726,028
	Allocate Cost of Service for Others		$0	$0	$0	$0	$0	$0	$0
	TOTAL COST OF SERVICE		$198,609,939	$52,520,846	$41,184,145	$51,090,512	$320,588	$0	$343,726,028
	%		57.78%	15.28%	11.98%	14.86%	0.09%	0.00%	100%
	RATE REVENUE		$170,064,667	$53,861,537	$44,188,703	$51,095,135	$256,249	$5,475,023	$324,941,314
	Allocate Rate Revenues for Others		$3,163,549	$836,576	$656,000	$813,793	$5,106	($5,475,023)	$0
	NON RATE REVENUE		$2,034,732	$644,424	$528,694	$611,326	$3,066	$65,506	$3,887,748
	Interruptible Credit		$0	$0	$0	$0	$0	$0	$0
	OffSystem Revenue		$8,085,989	$2,435,528	$1,975,356	$2,370,815	$16,517	$0	$14,884,205
	Excess Facility Revenue		$0	$0	$0	$0	$0	$0	$0
	Interdepartmental Sales		$6,679	$2,115	$1,735	$2,007	$10	$215	$12,761
	Allocate Non Rate Rev for Others		$37,974	$10,042	$7,874	$9,769	$61	($65,721)	$0
	TOTAL REVENUE		$183,393,590	$57,790,222	$47,358,363	$54,902,844	$281,009	$0	$343,726,028
	%		53.35%	16.81%	13.78%	15.97%	0.08%	0.00%	100%
	REVENUE DEFICIENCY		$15,216,349	($5,269,377)	($6,174,218)	($3,812,332)	$39,578	$0	$0
	% CHANGE		8.95%	-9.78%	-13.97%	-7.46%	15.45%	0.00%	0.00%

AQUILA NETWORKS - MPS

Cost-of-Service Allocation Methods

Line	Functionalization Category	Allocation Method
1	**Production:**	
2	Capacity	A&E Summer NCP
3	Energy	Total Year Sales
4	**Transmission:**	A&E Summer NCP
5	**Distribution:**	
6	Substations	Class Peak at Primary Voltage Level
7	Feeder Lines	Class Peak at Primary Voltage Level
8	OH Lines & Poles - Primary	All Customers - Weighted Customers
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22	Billing & Sales	All Customers
23	Assigned - LGS/LPS/SC	All Customers - LGS/LPS/SC
24	Assigned - RES/SGS	All Customers - RES/SGS

AQUILA NETWORKS - L&P

Recommended Inter-Class Revenue Adjustments

Line	Rate Class	Present Rate Revenue ($'000)	Required Change	Recommended First Step Change	
				Capped at 4%	Capped at 6%
		(1)	(2)	(3)	(4)
1	RES	$ 41,106	12.14%	4.0%	6.0%
2	SGS	$ 7,576	-12.04%	-4.0%	-6.0%
3	LGS	$ 17,729	-12.69%	-4.2%	-6.3%
4	LP	$ 22,910	-7.98%	-2.6%	-3.9%

AQUILA NETWORKS - MPS

Recommended Inter-Class Revenue Adjustments

Line	Rate Class	Present Rate Revenue ($'000)	Required Change	Recommended First Step Change	
				Capped at 4%	Capped at 6%
		(1)	(2)	(3)	(4)
1	RES	$ 170,065	8.95%	4.0%	6.0%
2	SGS	$ 53,862	-9.78%	-4.4%	-6.6%
3	LGS	$ 44,189	-13.97%	-6.2%	-9.4%
4	LP	$ 51,095	-7.46%	-3.3%	-5.0%
4	SC	$ 256	15.45%	*	*

* SC will be folded into an existing rate schedule