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

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| In the Matter of the 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. | )<br>)<br>)<br>)<br>) | Case No. EO-2002-384 |

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**STAFF'S PREHEARING BRIEF**

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# STAFF'S PREHEARING BRIEF

## EXECUTIVE SUMMARY

### ALLOCATION OF GENERATION-RELATED COSTS

In this section of the brief, the Staff sets forth its factual support and argument for why the most appropriate manner of allocating fixed generation costs to customer classes is on a time-of-use basis, which involves the consideration of customer class contribution to generation demand for every hour of the year, rather than solely at the hour of generation peak demand.

### ALLOCATION OF TRANSMISSION-RELATED COSTS

In this section of the brief, the Staff presents its factual support and arguments for why transmission costs should be allocated to customer classes on the same basis that generation costs are allocated to customer classes.

### PRIMARY DISTRIBUTION COST ALLOCATION METHOD

In this section of the brief, the Staff presents its factual support and arguments for why that portion of primary distribution costs that is identified in the class cost-of-service studies as being length- or customer-related should be allocated on density-weighted customer numbers.

## Determination and Implementation of Inter-class Revenue Adjustments

In this section of the brief, the Staff presents its factual support and arguments for why inter-class revenue adjustments should not be determined in this case and, instead should be determined and implemented in Aquila, Inc.'s current rate case, Case No. ER-2005-0436.

## Combination, Elimination or Addition of Rate Schedules

In this section of the brief, the Staff presents its factual support and arguments for when rate schedules should be combined, and states which modifications Aquila proposes that the Staff does not oppose.

## Changes to Rate Structures on Each Rate Schedule

In this section of the brief, the Staff presents its rationale and support for why the changes Aquila proposes to the rate structures on each rate schedule are inappropriate.

## Determination of Rate Values

In this section of the brief, the Staff presents its position that each rate value on the current rate schedules for each customer class should be increased by the same percentage amount the Commission determines is appropriate to move that class closer to its cost of service.

## Conclusion

In this section of the brief, the Staff presents its recommendation to the Commission that the Commission only determine in this case the appropriate allocation factors to be used in a class cost-of-service study and explains why it makes that recommendation.

## COST-OF-SERVICE ISSUES

### ALLOCATION OF GENERATION-RELATED COSTS

This case begins with the premise that the costs Aquila, Inc. incurs to serve each customer class—a group of customers that have similar characteristics—should be matched to the revenues Aquila gets from that group of customers. In this case the Staff, Aquila, Public Counsel and a group of parties—AG Processing, Inc., FEA, SIEUA—each sponsor a different approach for how to estimate the costs Aquila incurs to serve each customer class. The most significant issue between them in estimating the costs Aquila incurs to serve each customer class is found in the first stated issue on the list of issues: What is the appropriate method for allocating generation-related costs to customer classes?

The Staff's position is that its time-of-use method which (1) spreads each increment of fixed generation capacity costs equally across the entire time period where that capacity is used and (2) matches usage costs to when they are incurred is the appropriate method for allocating generation-related costs to customer classes.

Unlike the Staff, the witnesses of Aquila, AG Processing, Inc., the Federal Executive Agencies and the Sedalia Industrial Energy Users' Association promote the use of a generation cost allocation method that relies on maximum capacity requirements Aquila must meet during the year, *i.e.*, a peak responsibility method. (Staff witness Watkins Rebuttal, p. 1, l. 22 to p. 2, l. 4; p. 3, ll. 8-19).

The evidence and argument in this case will show that, because production-capacity costs are determined by loads throughout the year, each class's contribution to the sum of the class loads in each hour should be used to allocate hourly production-capacity costs. For consistency, and because production-energy costs also vary throughout the year, each class's contribution to the sum of class loads in each hour should be used to allocate hourly production-energy costs.

The electricity a utility provides to its customers must be created essentially instantaneously with when the customers use that electricity. (AG Processing, Inc./FEA/SIEUA witness Brubaker Direct, p. 4, ll. 14-21). Therefore, electric utilities must have sufficient generation capacity available to serve their customers at any given moment. The types of generating plants an electric utility relies on to supply that capacity at any given moment primarily depends on what mix of plants produces the least-cost electricity given the operational constraints of the plants, the costs of the plants and the costs of the energy sources the plants convert into electricity. (Staff witness Watkins Rebuttal, p. 2, ll. 6-9; p. 3, l. 21 to p. 4, l. 3, p. 4, ll. 4-12).

In allocating generation-related costs to customer classes, the Staff does not discriminate between customers in terms of the cost of the generation required to serve those customers at any given point in time. In this case the Staff had sufficient data to allocate generation costs in each hour of the year to customer classes, hour-by-hour. (Staff witness Watkins Direct, p. 5, ll. 8-18). With the Staff's method, the generation costs assigned to each customer class in each hour is based only on the amount of electricity that customer class uses in that same hour. The Staff's method, in each hour of the year, allocates to the customer classes Aquila's costs related to generation used in that hour to meet the electricity demands of the customers in those classes in that same hour, based on the electricity used by each customer class in that hour.

In three cases decided in the early and mid-1980s the Commission adopted the position the Staff takes here. In each case, the issue was both significant and hotly contested. The first case is *In the matter of Arkansas Power & Light Company of Little Rock, Arkansas, for authority to file tariffs increasing rates for electric service provided to customers in the Missouri service area of the Company,* Case No. ER-81-364 (Report and Order, April 20, 1982), 25 Mo. P.S.C. (N.S.) 101. In its Report and Order the Commission stated the Staff suggested that the most appropriate manner of allocating fixed generation and transmission costs to customer classes was on a time-of-use basis, which involves the consideration of customer class contribution to generation demand for every hour of the year, rather than solely at the hour of generation peak demand; however, due to data limitations the Staff presented an average and peak method. 25 Mo. P.S.C. (N.S.) at 106-07. In that case the company relied on a peak responsibility method—the coincidental peak allocation method. *Id*. In addressing the issue of what method to employ for allocating fixed generation and transmission costs the Commission stated the following:

> Based upon the evidence and arguments presented in this case, the Commission cannot conclude that the coincidental peak method, as advocated by AP&L and the Mining Intervenors, represents a reasonable method for allocating fixed generation and transmission costs. The arguments of these parties are not persuasive in support of the use of the coincidental peak method. The fact that the Company's total generating capacity must be sufficient to meet peak demand does not, of itself, indicate that class contribution to demand at the time of system peak is an appropriate method for explaining class causation of fixed generation and transmission costs.
>
> In evaluating application of the coincidental peak method to the allocation of fixed generation and transmission costs, consideration of several points is of prime importance. First, no matter which allocation method is used, each customer class will be assigned a percentage of AP&L's *total* jurisdictional fixed generation and transmission costs. It is the percentage share of the total of these costs which each customer class will be assigned that varies depending upon the allocation method chosen. Secondly, these costs consist primarily of the investment for electric generating capacity. These generating facilities can be broadly divided into the categories of baseload, intermediate and peaking units. As discussed previously, these units have different cost characteristics, with baseload units having relatively high capital costs and relatively low operating costs, and, conversely, peaking units having relatively low capital costs and relatively high operating costs.

25 Mo.P.S.C. (N.S.) at 114-15. The Commission noted that AP&L's baseload units accounted for most of the company's capacity yet allocation of the cost of those units based on coincident peak would make low load factor customers' (residential) relative contribution to demand high and make high load factor customers' (*e.g.* large power class) relative contribution to demand low, although those baseload units would generally operate throughout the year. In other words, the residential class would be assigned a disproportionately high level of the generation costs and the large general service class would be assigned a disproportionately low level of the generation costs. 25 Mo.P.S.C. (N.S.) at 115.

In the second case, *Re Kansas City Power and Light Company*, 53 PUR4th 315, 25 Mo. P.S.C. (N.S.) 605 (Case No. EO-78-161, March 30, 1983 Report and Order), the Commission made cost-of-service determinations based on load data collected in response to a July 1974 Commission order. In the beginning summary section of that order the Commission stated:

> . . . . As will be discussed in greater detail below, we find that an appropriate manner of proceeding from this docket is to direct KCPL to perform an updated cost-of-service study to be submitted in conjunction with its next Missouri general rate case subsequent to its presently pending rate case, Case Nos. ER 83 49, ER 83 72, and EO 82 65. Said updated cost-of-service study shall contain those methods and elements found to be appropriate in this report and order. Additionally, the lack of a clear record in this case regarding internal class rate design issues suggests that these issues cannot be resolved in this case. Issues regarding KCPL's internal class rate structures should be raised in the company's next Missouri general rate case subsequent to its pending rate case.
>
> The most important of the cost-of-service determinations made in this case involves the method for allocating fixed generation costs. As stated above, the updated cost-of-service study to be submitted by KCPL with its next Missouri general rate case should contain the methods and elements found to be proper in this report and order. As will be discussed in greater detail, infra, based on the evidence presented in this case, *the commission finds the time-of-use method to be the most theoretically appropriate approach for allocating generation costs* (emphasis added) and, further, finds the average and peak allocation method for fixed generation cost as the most reasonable alternative to a full time-of-use procedure. As a result of these findings, the updated cost-of-service study to be submitted by KCPL shall contain either: (a) a full hourly time-of-use allocation of

> both fixed and variable generation costs to the customer classes, or (b) an average and peak allocation of fixed generation costs and an allocation of variable generation costs on the basis of annual class energy usage adjusted for losses.

25 Mo. P.S.C. (N.S.) at 607.

In the body of its order the Commission described KCPL's fixed generation costs allocation methods as follows:

> *Kansas City Power and Light Company.* The company submitted two cost-of-service studies in this proceeding with the only difference between the studies consisting in the choice of allocation factor for the assignment of fixed generation costs to the customer classes. One study used the "coincidental peak method" (also referred to as the "single-peak method") whereby all fixed generation costs are assigned to the customer classes in proportion with the percentage contribution of each class to system demand at the hour of system peak demand. For KCPL, system peak demand occurs during the summer months. Kansas City Power and Light Company's other cost-of-service study used a combined summer and winter peak demand method, by which each customer class's percentage contribution both to the company's summer and winter peak demand hours are calculated and, together, form the basis for the share of fixed generation costs allocated to the customer classes. Both of these allocation methods can be categorized as "peak responsibility" methods in that they associate class causation of fixed generation costs with peak demand (in the first instance, system peak demand and, in the second, seasonal peak demands).

25 Mo. P.S.C. (N.S.) at 610-11.

In contrast it stated the Staff presented the following approach as an alternative to using a peak responsibility method:

> In its prepared rebuttal testimony and in its initial brief submitted herein, the staff takes the position that the "additional cost method" (also, referred to as the "time-of-use method") is the most theoretically correct procedure for allocating fixed generation, bulk transmission and energy costs to the customer classes. The additional cost method entails estimation of class contribution to system demand during each of the 8,760 hours of the year, identification of the generating plants operating during each hour and the capacity and energy costs associated with these plants, and the assignment of fixed generation, bulk transmission and energy costs to the customer classes based upon a matching of class demand contribution levels with the cost characteristics of the generating plants operating throughout the year.

Recognizing that the additional cost allocation method requires the accumulation of a significant amount of load research data, the staff's position at the hearing was that the data requirements make regular use of the additional cost method impractical. In this context, the staff recommends that the commission approve use of the "average and peak method" for allocating fixed generation and bulk transmission costs as an approximation of the results of an additional cost allocation of fixed generation, bulk transmission, and energy costs. The average and peak method allocates costs in the following manner: The average demand, as a percentage of peak demand, is determined and is applied to each class's percentage contribution to average demand; then, the difference between peak demand and average demand, as a percentage of peak demand, is determined, and is applied to each class's percentage contribution to peak demand. The results for each class are then combined to produce the average and peak class allocation factors.

In summary, the staff's recommendation for allocating fixed generation and bulk transmission costs is to use the average and peak method if the commission finds the additional cost approach to be theoretically correct or, alternatively, to use the 100-peak-hours method if the commission finds peak responsibility to be the proper allocation approach.

25 Mo. P.S.C. (N.S.) at 611-12.

In its conclusions the Commission stated:

*Conclusions*. A number of the methods proposed by the parties to this proceeding for the purpose of allocating fixed generation and bulk transmission costs to the customer classes can be categorized as peak responsibility methods. The common element of peak responsibility methods is an emphasis on peak demand or demands as the basis for assigning costs. The peak responsibility methods proposed in this case include: the coincidental peak (or single-peak) method advocated by Armco/GM and GSA; KCPL's combined summer and winter peak method; the staff's 100-peak-hours method; and DOE's marginal cost method using peak rating periods and relative loss of load probabilities.

The coincidental peak method is the purest form of peak responsibility allocation in that it assigns costs to each customer class based solely upon the contribution of each class to system demand at the single hour of system peak demand. Certain alternative peak responsibility approaches, such as KCPL's combined summer and winter peak method and the staff's 100-peak-hours method, give reduced weight to class contribution to demand during the single hour of system peak demand but, nevertheless, are premised on the principle that it is the system's peak demands which comprise the primary factor upon which the allocation of fixed generation and bulk transmission costs should depend.

The commission has previously considered the question of the proper allocation of fixed generation and bulk transmission costs in *Re Arkansas Power & Light Co.* Case No. ER 81 364, April 30, 1982 ("AP&L decision"). The rationale proffered in support of peak responsibility allocation methods in the instant case (that peak demand is the primary determinant of total generation capacity) was rejected in the AP&L decision as a basis for explaining class causation of these costs. While there can be no argument as to the critical importance of peak demand in capacity planning decisions, it does not follow that class contribution to peak demand provides an appropriate method for class allocation [of] fixed generation and bulk transmission costs.

As pointed out in the AP&L decision, these costs consist mainly of investment in electric generating facilities. The majority of these costs are related to base-load and intermediate plants which have relatively high capital costs and low running costs relative to peaking units, and which generally operate throughout the year. Peak responsibility methods emphasize class contribution to system peak demands in determining each class's share of these costs. Low load factor customer classes tend to contribute a relatively large proportion to demand at times of system peak as compared to demand at nonpeak hours, while high load factor customer classes tend to contribute a relatively small proportion to demand at times of system peak as compared with demand at nonpeak hours.

Thus, the inequity inherent in peak responsibility methods for allocating these costs to the customer classes is that the majority of the costs to be allocated relate to plants operating throughout the year, while the proportionate shares of these costs to be borne by the customer classes are determined by reference only to class demands during peak hours. The coincidental peak method is the least equitable of the peak responsibility methods proposed in that it places total dependence on the single hour of system peak demand. However, for the reasons stated herein, the commission finds that the evidence presented leads to the conclusion that peak responsibility methods, generally, do not provide appropriate and equitable allocations of fixed generation and bulk transmission costs to the customer classes.

* * * *

In the AP&L decision, the commission considered and rejected a similar recommendation by public counsel regarding allocation of Arkansas Power and Light Company's fixed generation and bulk transmission costs. Therein, while acknowledging that base-load generating units generally have lower running costs and higher capital costs as compared with peaking units, the commission was not persuaded that this fact should justify the allocation of investment in base-load capacity on the basis of class energy usage. As further noted therein, the goal of electric utility capacity planning should be the maintenance of sufficient capacity to meet projected system demands at the lowest total cost. As pointed out by public counsel, there are capacity cost/fuel cost "trade-offs" involved in decisions between building base-load versus peaking units. The composition of a utility's existing generating system, the shape of its load duration curve, and the cost characteristics of the generating unit candidates should be considerations in making a capacity expansion choice. Thus, public counsel's proposed allocation approach of categorizing planned capacity additions on the basis of benefits to be derived, such as the saving of fuel costs or the meeting of growth in peak demand, constitutes an oversimplification of the capacity planning process.

An additional problem with public counsel's approach is that it would allocate capacity costs associated with all existing generating facilities on the basis of an evaluation as to the benefits to be derived in building specific types of new units. The logic of public counsel's argument would call for an evaluation of the benefits derived from building each of the company's existing generating facilities, and the commission finds that such an approach is neither warranted nor capable of practical implementation.

A determination is made as to the propriety of including investment associated with a particular generating facility in a utility's cost of service when the company requests rate base treatment of the investment through a rate case. Such costs are "fixed" in nature in the sense that they generally will not vary depending on energy output but, instead, will be incurred by the utility regardless of energy levels. Once a commission determination has been made that a particular utility investment in generating facilities should be included in the company's cost of service, the commission finds that, for purposes of allocating costs to the customer classes, costs which are fixed in nature are appropriately allocated by reference to some type of customer class demand levels. Therefore, the commission concludes that public counsel's proposal to allocate fixed generation and bulk transmission costs on the basis of class energy usage is not justified by the evidence presented.

The commission agrees with the staff's position that the additional cost (time-of-use) method is the most theoretically appropriate approach for allocating fixed generation, bulk transmission, and energy costs to the customer classes. The generating facilities of KCPL are not homogeneous in nature but, rather, include plants with varying characteristics in terms of fixed and variable costs. Thus, customer class responsibility for the incurrence of these costs varies throughout the year depending upon hourly class demand levels and the "mix" of plants being used to meet the hourly loads. The time-of-use allocation approach is designed to consider these factors in making cost assignments to the customer classes.

The staff has suggested in this case the data requirements associated with the time-of-use allocation method may make its implementation on a regular basis impractical. However, no evidence has been presented by KCPL or any other party which would support a conclusion that the data requirements for time-of-use allocations would place an undue burden on the company. In this regard, the commission notes that Arkansas Power and Light Company is presently under a commission directive to collect and prepare load research data necessary for performing time-of-use allocations in a cost-of-service study to be submitted in conjunction with that company's next Missouri general rate proceeding.

The staff has recommended that the commission adopt the average and peak method for allocating fixed generation and bulk transmission costs if peak responsibility methods are rejected and the additional cost (time-of-use) allocation method is found to entail unduly burdensome data requirements. The staff supports the average and peak method as providing a reasonable approximation of the cost assignments which would result from allocating fixed generation, bulk transmission, and energy costs through the time-of-use procedures.

In the AP&L decision, the commission approved the average and peak method as the most reasonable approach of those presented therein for allocating fixed generation and bulk transmission costs. In that case, the staff also recommended use of the average and peak method as a proxy for the time-of-use allocation procedure since the data necessary for time-of-use allocations had not been available for use in that proceeding. The commission recognized that, while the average and peak method does not purport to track use of generation and bulk transmission facilities throughout the year, as is the case with the time-of-use procedure, the average and peak method does give consideration to off-peak usage of these facilities by allocating a portion of the involved costs on the basis of class contribution to average demand. These findings regarding the average and peak method which were made in the AP&L case are not contradicted by the evidence presented in the instant proceeding.

Armco/GM oppose the staff's recommendation in support of the average and peak method for allocating fixed generation and bulk transmission costs, but argue that if this method is to be utilized for allocating such costs, then the average and peak method should also be utilized for the allocation of energy costs. The usual method for allocating energy costs is on the basis of class kilowatt-hour sales adjusted for losses. The Armco/GM argument for applying the average and peak procedure to the allocation of energy costs is premised on the assumption that the average and peak allocation of fixed generation and bulk transmission costs results in high load factor customers bearing a disproportionately large share of such costs, and because of this alleged disproportionate burden, such high load factor customers should be allocated a reduced portion of energy costs. This same argument was advanced by the mining intervenors in the AP&L case and was rejected by the commission on the basis that it assumes the propriety of using the coincidental peak method or peak responsibility methods, generally, for allocating fixed generation and transmission costs. The commission rejected both the coincidental peak method and the mining intervenors" proposed application of the average and peak method to energy costs in the AP&L case and no evidence has been presented in this record which persuades the commission that application of the average and peak method to energy costs is appropriate in this proceeding.

> Therefore, based on the findings that fixed generation and bulk transmission costs should be allocated to the customer classes based on class demand levels and that the average and peak method gives a degree of consideration to off-peak usage of generation facilities, the commission concludes that the average and peak method, as proposed by the staff, provides the most reasonable alternative to the time-of-use procedure for allocating the costs involved.

25 Mo. P.S.C. (N.S.) at 613-17.

In the third case, *Re Union Electric Company*, 66 PUR4th 202, 27 Mo. P.S.C. (N.S.) 166, Case Nos. EO-85-17, ER-85-160 (Missouri Commission, Report and Order March 29, 1985) the Commission again addressed the issue that is before the Commission in this case: Should fixed generation capacity costs be allocated based on system peak demand or on total system demand? In that case the Commission characterized the issue as follows:

> The parties are in fairly uniform agreement that the proper method chosen to allocate costs should assign costs based upon cost causation as closely as practical. The parties here present two basic theories concerning what causes costs and how to assign those costs. The two approaches of the parties separate over the issue of whether capacity is built to meet system peak demand or total system demand. Staff and PC support the theory that the need for generating capacity is caused by total system demand. UE, industrials, Dundee, and MSD support the principle that generating capacity is caused primarily by system peak demand. Retailers agree with staff and PC on the causation issue, but reject staff and PC's method of allocating costs. Staff, PC, UE, industrials, and retailers have presented cost-of-service studies for allocating the total revenue requirements among the customer classes.
>
> Although the parties have approached the allocation of cost to the classes on a cost causation basis, there are other influences which affect the ultimate rates to be charged individual customers. The commission agrees that allocating the costs of providing service to the classes and customers who cause these costs is the basic function of the rate design of a public utility company. The commission, though, is also aware of other influences which affect the ultimate decision of what price a customer should pay for electric service. The straight assignment of costs to customers based upon any allocation method chosen by the commission will be tempered by attempts to ensure the efficient use of the service and social policies regarding use of the service.
>
> Rate design in this case involves two concerns. The first concern is the impact rate design will have upon the various classes where any change is made

> in the method of allocation. The other concern is that the rate design adopted will be the method by which the substantial increase in rates caused by the Callaway plant will be allocated.

27 Mo. P.S.C. (N.S.) at 275-76.

As Aquila, AG Processing, Inc., the FEA, and the SIEUA present here, in that case UE presented cost-of-service studies using peak responsibility methods. As to those methods the Commission stated:

> . . . . These methods are based upon the underlying principle that the company's capacity requirements are determined by peak demand. To allocate costs on a causation basis, UE contends, one must look both at the amount of capacity needed to meet the system peak and the amount of energy needed to meet the system energy needs. UE's position is that capacity costs are fixed and are related to demand. These costs do not change with kilowatt-hour consumption. Variable costs are those associated with fuel costs (energy) and do vary with kilowatt-hour consumption. UE contends that fixed production capacity should be allocated on a demand basis and not by a kilowatt-hour or variable basis.
>
> UE contends that the coincident peak method of allocation places the cost of additional capacity on the customers causing increased peak demand. Offpeak customers do not cause the additional capacity, but in fact made the system more efficient by using capacity during nonpeak periods, thus increasing UE's load factor. UE contends these offpeak customers benefit the system by increasing the load factor of the system and thereby reducing overall costs. Since these offpeak customers do not cause additional capacity, they should not be allocated costs for their offpeak use. UE views its system as having fixed capacity; any new capacity is constructed to meet peak use and peak users should bear the cost of its construction.

27 Mo. P.S.C. (N.S.) at 276.

In the UE case, as in the AP&L and KCPL cases, the Staff took the position that production capacity costs are caused by the total demand on the system. The Commission described the Staff's position in that case as follows:

> . . . . Staff's position is that production capacity costs are caused by the total demand placed on the system. The total demand on the system varies from hour to hour throughout the year. The generating units are categorized as base load, intermediate, and peak. The utilization (mix) of these different types of generating units will vary throughout the year in relation to such factors as hourly

system demand, unit availability, incremental running costs of available units, and the availability of power on UE's interconnect system. Staff contends that as the mix varies, so do total costs vary.

Staff's cost-of-service study is based upon these variations of plant mix and customer usage throughout the year. It asserts the theoretically most correct approach to designing rates is based on this condition and is a method that determines the production costs of meeting system demand in each hour of the year. Thus the method should create 8,760 power pools to be allocated to customer classes based upon their use of the system during the hourly pools. This method is described as a time-of-use (TOU) method. Staff states, though, that there is insufficient load data to determine hourly demand for the UE system. Staff has thus proposed a TOU/average-and-peak (AP) method which it considers most closely approximates the preferable hourly TOU method. The AP method allocates the monthly production (capacity and running) costs to the classes based upon the class contribution to system average and to system peak demands. Production capacity costs related to average demand were allocated to classes based on their monthly contribution to energy measured with losses, and production capacity costs related to peak demand were allocated to classes based upon their monthly contribution to coincidental peak demand. The separation between average and peak demand was determined by use of a monthly loading factor for each power source (plant). Average demand was determined by multiplying the monthly plant loading factor times the monthly capacity costs. This figure was then subtracted from total costs to give the peak demand figure.

Staff developed a TOU production costing model to simulate operations of the UE system. Staff's production costing model was then used to allocate production capacity and running costs to the months. Staff then allocated the monthly costs to the classes through the AP method, since hourly load data was not available for a TOU allocation. Staff contends the AP method most closely matches the TOU hourly method. Underlying staff's cost-of-service study are the principles of cost causation staff feels are correct. Staff states the CP methods answer the wrong question concerning production capacity costs. The question is not the timing of future capacity additions and megawatt amount of those additions, but rather the responsibility of each customer class for the causation of the utility's embedded production capacity costs. The proper method for answering the question is to determine how UE's power sources (plants) are utilized by the classes. Staff asserts its TOU/AP method accomplishes this goal.

Staff bases its position on the premise that capacity utilization throughout the year is the proper method to allocate costs. It has classified production costs as capacity costs and running costs. Capacity costs are the replacement costs for each source of supply (plants); running costs are fuel and variable operating and maintenance costs. Staff's method views the UE system from a standpoint of what types and how much capacity would be purchased to meet demands in every hour of the year if it is assumed no production plant exists at the beginning of the year.

27 Mo. P.S.C. (N.S.) at 276-77.

Worthy of note in the UE case is that at least one party, the retailers, proposed the use of a 4CP average excess method for allocating fixed generation capacity costs. Much as Aquila does in its testimony here, the retailers in that case "contend[ed] that the 4CP/AE method represents a reasonable middle position on the issues involved in this case." 27 Mo. P.S.C. (N.S.) at 279. The Commission also stated, "Retailers' 4CP/AE method is offered as a middle ground between the extremes of TOU and 2CP, and thus would arguably provide a method for moving to cost-based rates without a major change in commission position on rate design." 27 Mo. P.S.C. (N.S.) at 279.

As in this case, in the UE case "[t]he decision of what cost-of-service study most closely reflects the class responsibility for the UE system most dramatically impacts on the distribution of production generation costs." 27 Mo. P.S.C. (N.S.) at 279.

In the paragraph where the Commission states its decision on this issue the Commission states:

> The main concern of the commission is to determine which theory most reasonably reflects the causation of production costs on the UE system. As stated earlier, the commission has accepted in prior decisions, and again accepts, the TOU method as the most reasonable method for allocating the production costs of serving the various classes. The commission thinks that staff's position concerning causation is the most accurate and reasonable concerning the UE system. The Commission finds the evidence in this case supports the adoption of the TOU method. To adopt a CP method, one must first accept the contention that UE only builds new capacity to meet peak demand. The commission cannot accept this. It is obvious Callaway was built to meet both base load and peak demand, and its cost should be shared on that basis. The Callaway plant is the first plant in UE's loading order and UE will operate the Callaway plant as long as possible year-round.

27 Mo. P.S.C. (N.S.) at 281-82.

Finally, in addressing the use by Staff of replacement costs rather than historical costs, the Commission made the following observation regarding the Staff's approach: "Staff's method is based upon the concept that each class is responsible for its utilization of the system at any given hour." 27 Mo. P.S.C. (N.S.) at 284.

In a later rate design case, *In the matter of the investigation of the electric class cost of service for St. Joseph Light & Power Company,* 1 Mo. P.S.C. 3rd 450 (Case No. EO-88-158, December 11, 1992 Report and Order), the Commission addressed the cost of service for St. Joseph Light & Power Company, the predecessor to Aquila Networks-L&P. In that case the parties agreed to use three customer classes: Residential, General Service and Large Power. 1 Mo. P.S.C. at 453. Costs were taken from the calendar year 1990. *Id.* And the parties agreed some form of "Average and Peak" allocator should be used to allocate production capacity. 1 Mo. P.S.C. 3rd at 455. They agreed that the "Average Demand" portion should be allocated on "Annual Energy," but disagreed on the "Split Between Average and Peak" and what "Peak Demand" should be used. In that case the Staff advocated use of class peak demands from each of the twelve months in the test year to calculate the peak demand allocator. St. Joseph Light & Power Company and AG Processing, Inc. advocated use of the class contribution to peak demand to calculate the peak demand allocator. The Commission stated:

> The Commission is of the opinion that the class noncoincident peak demands from each of the twelve (12) months (12NCP), with each month weighted according to capacity utilization, should be used as the peak demand allocator. This allocation method accounts for the fact that the amount of PRODUCTION-DEMAND is driven by the need to meet varying peak demand levels throughout the year. By weighting each class's monthly NCP by capacity utilization, the Staff's and Public Counsel's method places greater emphasis on peak months in recognition of the significant impact system peak has upon the peak portion of costs in the PRODUCTION-DEMAND function. The Staff's and Public Counsel's peak demand allocator (12NCP weighted by each month's capacity utilization) assigns responsibility for peak demand costs accurately and minimizes the instability that may result from allocating such costs on the basis of

class contribution to: (1) the system peak during the test period as advocated by AGP, or (2) an average of the two system peaks each in 1989 and 1990 as advocated by SJLP.

SJLP argues that Staff's and Public Counsel's method places too much responsibility on the Large Power class and not enough responsibility on the Residential class. SJLP also argues that not enough recognition is given to the system peak demand. SJLP argues that the use of 12 noncoincident demands does not recognize the system maximum peak demand placed on the system by its customers. SJLP also argues that AGP's method give the high load factor customer too high of a recognition for its benefits to the system. SJLP argues that using its method places an equal responsibility for the coincident peak demands and the annual energy requirements. Coincident demand is the classes' demand at the time of system maximum demand.

The Commission is of the opinion that AGP's peak demand allocator is extremely narrow, focusing on *one* hour from the test year. It is premised on the assumption that the amount of PRODUCTION-DEMAND is determined *solely* on the basis of the 1990 system peak. SJLP's method places equal weights on the two highest peak demands from *both* 1989 and 1990. By using a four-period average to measure the classes' peak responsibility, SJLP has attempted to minimize the volatility inherent in measuring coincident peak on the basis of a single hour as advocated by AGP, due to the fact that the peak may have been caused by an unpredictable event that is not likely to be repeated. However, the Commission is of the opinion that a 12-month demand allocation method is preferable in that it is based on the principle that a utility installs facilities to maintain a reasonably constant level of reliability throughout the year or that significant variations in monthly peak demands are not present. Under this method, no single peak demand or combination of single peak demands is of any significantly greater magnitude than any of the other monthly peak demands. Thus, the relative importance of each month is considered. Also, the NCP method attempts to give recognition to the maximum demand placed upon a system during the year by all customers. This method is based on the theory that facilities are sized to meet these maximum demands. Therefore, the costs of the facilities are allocated in accordance with each customer's contribution to the sum of the maximum demands of all customers imposed on the facilities. The monthly average NCP demand allocation method attempts to give recognition to the variation or diversity among monthly NCP demands placed on a system during the year by all customers. This in effect recognizes the fact that facilities are installed to provide reliable service throughout the year, including periods of scheduled maintenance. Costs of the facilities are allocated in accordance with each customer's average monthly contribution to the sum of the average monthly maximum demands of all customers. Also, the Commission is of the opinion that capacity utilization places greater emphasis on peak months in recognition of the significance that system peak has upon the peak portion of costs in the PRODUCTION-DEMAND function. This method counteracts the argument of

> SJLP that not enough recognition is given in the Staff's and Public Counsel's method to system peak demand. While not giving the recognition to system peak demand that SJLP's method gives, Staff's and Public Counsel's method assigns a more appropriate level to system peak demand, in the Commission's opinion.
>
> Staff's and Public Counsel's position for the allocation for the peak demand portion of PRODUCTION-DEMAND costs using class noncoincident peak demands from each of the twelve (12) months (12NCP), with each month weighted according to capacity utilization, is adopted by the Commission.

1 Mo. P.S.C. 3rd at 455-57.

Staff's method here has the same attributes as those the Commission described in the foregoing case, except that it is less granular, breaking the allocation down hour-by-hour rather than month-by-month and, thus, eliminates the need to use class peak demand.

Unlike the foregoing cases, here the Staff had sufficient data and resources to perform its time-of-use method and, therefore, here, the Staff did not use an average-and-peak method. In all other respects, the statements quoted above made by the Commission in these foregoing cases are equally applicable here. The contentions of Aquila, AG Processing, Inc., the FEA, and the SIEUA that a peak responsibility method should be followed, rather than following an established norm, are a renewed effort to convince the Commission to adopt an approach the Commission discarded some 25 years ago.

The Commission should reject the proposals of Aquila, AG Processing, Inc., the Federal Executive Agencies and the Sedalia Industrial Energy Users' Association because they, by relying on a peak responsibility method, assume that all generation is added to serve peak load.

The position of the Office of the Public Counsel on this issue is that both demand and energy characteristics of a system's loads are important determinants of production plant costs. Office of the Public Counsel witness Meisenheimer states:

> . . . . I allocate the Production Plant according to (1) 12-month non-coincident peak (NCP) average and peak allocators and (2) an energy (kWh) allocator. The first allocation method is a reasonably close approximation to a TOU method which the Commission has previously determined reasonable. The latter allocation method is applied to costs that vary primarily based on fuel consumption or the amount of time generation units are utilized.

(Public Counsel witness Meisenheimer Direct, p. 5, l. 21 to p. 6, l. 4). Because the Staff has employed a time-of-use method and developed hourly time-of-use allocators, the Commission should not adopt the Office of the Public Counsel's "reasonably close approximation" to a time-of-use method.

## ALLOCATION OF TRANSMISSION-RELATED COSTS

The second issue presented for determination by the Commission is: What is the appropriate method for allocating transmission-related costs to customer classes? The evidence and argument in this case will show, for consistency, and because the planning and operation of transmission plant is inexorably linked to production plant, each class's contribution to the sum of class loads in each hour should be used to allocate hourly transmission-capacity costs.

In *Re Union Electric Company*, 66 PUR4th 202, 27 Mo. P.S.C. 166 (N.S.) (Case Nos. EO-85-17, ER-85-160 March 29, 1985 Report and Order), the Commission also addressed allocation of transmission costs. There the Commission said,

> Production and transmission costs are so closely linked that usually they are considered together when determining how those costs should be allocated. Because of the Callaway plant, the commission has separated production costs from transmission costs, as well as other costs, for purposes of determining the impact of Callaway on production costs. The commission, though, does not consider it reasonable to adopt one method for production costs and a different one for transmission costs.
>
> The commission has determined that staff's TOU/AP method is the appropriate method for allocating production costs, and the commission also considers staff's method the appropriate method for allocating transmission costs.

27 Mo. P.S.C. (N.S.) at 286. Further, in *In the matter of the investigation of the electric class cost of service for St. Joseph Light & Power Company,* 1 Mo. P.S.C. 3rd 450 (Case No. EO-88-158, December 11, 1992 Report and Order), one of the parties, AG Processing, Inc., proposed a different allocator for transmission costs than it sponsored for production costs. The parties had agreed to use of an "Average and Peak" allocator to allocate production capacity costs; however, AG Processing, Inc. advocated use of a coincident peak allocator for transmission costs on the basis that "transmission facilities are built to meet peak load requirements of the system." 1 Mo. P.S.C. 3rd at 457. In response the Commission determined:

> The Commission is of the opinion that the same allocator should be used for both PRODUCTION-DEMAND and TRANSMISSION-DEMAND. The primary reason is that production plant and transmission plant are designed to meet the same criteria. AGP has argued that a transmission plant is different from a production plant in that it is built to meet peak load requirements of the system, and therefore, the costs for such should be allocated on the basis of one coincident peak. The Commission is of the opinion that the transmission plant is not different from the production plant but that it should be considered to be an extension of the production plant, where the planning and operation of one is inexorably linked to the other. Thus, the major factors that drive production costs also tend to drive transmission costs as well. The allocator adopted herein for PRODUCTION-DEMAND does in fact take into consideration peak demand. As previously stated in that issue, however, the Commission does not believe that peak demand is the sole determining factor in either PRODUCTION-DEMAND or TRANSMISSION-DEMAND. The Commission is of the opinion that peak demand is one factor among others, including energy requirements throughout the year, that should be utilized in determining an appropriate PRODUCTION-DEMAND or TRANSMISSION-DEMAND allocator.

1 Mo. P.S.C. 3rd at 457-58.

While they disagree on which method it should be, each party that takes a position on this issue allocates most or all transmission costs by the same method that party uses to allocate production-capacity costs. (Staff witness Busch Direct, p. 11, l. 21 to p. 12, l. 7; Aquila witness Tracy Direct, p. 11, ll. 4-6; AG processing, Inc./FEA/SIEUA witness Brubaker Direct, p. 19, l. 9 to p. 21, l. 8 and Rebuttal, Schedule 1R, p. 3; Public Counsel witness Meisenheimer Direct, p. 5,

l. 18 to p. 6, l. 15). The Commission should adopt the same method for allocating transmission costs that it adopts for allocating production-capacity costs.

## PRIMARY DISTRIBUTION COST ALLOCATION METHOD

The third issue presented to the Commission is: What is the appropriate method for allocating that portion of primary distribution costs that is identified in the class cost-of-service studies as being length- or customer-related?

All parties, except the Office of the Public Counsel, agree that a portion of the primary distribution system costs should be allocated on density-weighted customer numbers because the length of the system depends on how may customers are served and how close together they are, as well on their load. (AG processing, Inc./FEA/SIEUA witness Brubaker Rebuttal, p. 7, l. 15 to p. 8, l. 7; Staff witness Busch Direct, p. 8, l. 12 & 14 and p. 13, ll. 11-19; Staff witness Busch Rebuttal, p. 3, ll. 5-11; Aquila witness Stowe Direct, p. 16, l. 11-14 and p. 8, Table 2.)

To the extent that Public Counsel witness Meisenheimer's criticism is based on rejecting the minimum system approach to determining the customer-related portion of the primary distribution system costs and double allocating a portion of the demand-related costs to low usage customers, her criticism is not valid. The customer-related portion of the primary distribution system costs was not determined by the minimum system approach. Nor has a portion of the demand-related costs been double allocated to low usage customers. (Staff witness Watkins Surrebuttal, p. 5, l. 22 to p. 6, l. 4.)

## RATE DESIGN ISSUES

### DETERMINATION AND IMPLEMENTATION OF INTER-CLASS REVENUE ADJUSTMENTS

The fourth issue presented to the Commission, but the first rate design issue, is: Should inter-class revenue adjustments be determined in this case and should inter-class revenue adjustments be implemented in this case?

Changes in the distribution of costs and revenues since Aquila's last rate case have affected the class revenue shifts that would be required to align revenues with the cost of serving each customer class. The class cost-of-service studies presented in this case are all based on the distribution of costs and revenues from Aquila's last rate case, Case No. ER-2004-0034, a test year of calendar year 2002, updated for known and measurable changes through September 30, 2003. (Aquila witness Stowe Direct, p. 10, ll. 7-9). Class revenue shifts should be based on the distribution of costs and revenues determined by the Commission in Aquila's current rate case, Case No. ER-2005-0436, and should be implemented in that case.

The Staff has performed that analysis in Aquila's pending rate case and the results of its class cost-of-service study are quite different from the results based on costs and revenues determined in Aquila's last rate case. The parties in this case used cost data from that last rate case for the studies they performed in this case. (Staff witness Watkins Surrebuttal, p. 6, ll. 18-21).

### COMBINATION, ELIMINATION OR ADDITION OF RATE SCHEDULES

The fifth issue presented to the Commission, the second rate design issue, is: What rate schedules should be combined, eliminated or added?

There are instances where different rate schedules were implemented for certain groups of customers within the same customer class because of customer impacts, not because of cost differences. In those instances, the rate schedules should be combined. (Staff witness Watkins Direct, p. 3, ll. 7-10). The Staff has no objection the Company's proposals to:

(1) Add an MPS Residential – Other Use rate schedule;

(2) Combine the MPS Small GS-No Demand (MO710), School and Church (MO740), and Municipal Park and Recreation (MO800, MO810, MO811) rate schedules into a single MPS Small General Service – Non Demand Billing rate schedule;

(3) Freeze the availability of the existing MPS Small General Service – Primary Voltage rate schedule to service to existing customers only;

(4) Consolidate MPS Rate Schedule MO919 into the MPS Large Power Service-Secondary (MO730) rate schedule;

(5) Add an MPS Small GS Short Term Service rate schedule-;

(6) Merge the L&P Residential Water Heat (MO913, MO914) rate schedule into the L&P Residential General Use (MO910, MO911) rate schedule;

(7) Consolidate the L&P Small General Service-Limited Demand rate schedules (MO930, MO932, MO934, MO941) into a single L&P Small General Service-Non Demand Billing rate schedule;

(8) Merge the L&P Small General Service-with Space Heat (MO933) rate schedule into the L&P Small General Service-General Use (MO931) rate schedule; and

(9) Add an L&P Small General Service Short Term rate schedule.

## CHANGES TO RATE STRUCTURES ON EACH RATE SCHEDULE

The sixth issue presented to the Commission, the third rate design issue, is: What changes to the rate structures on each rate schedule are appropriate?

None.

Staff opposes Aquila's proposed rate structure changes because the current rate structures work fine, the proposed rate structures are not supported by any analysis, and Staff's review of these rate structures (and rate values) uncovered a number of serious rate design features that send the "wrong" price signals to customers. (Staff witness Pyatte Direct, p. 11, ll. 6-12; Staff witness Pyatte Surrebuttal, p. 1, l. 27 to p. 2, l. 3 and p. 3, l. 18 to p. 12, l. 4). In particular, Staff witness Pyatte observed on a cursory review of Aquila's proposed rate structures the following features that are symptomatic of a flawed rate design:

- Higher rates are proposed to be charged for summer energy use by MPS Residential-General Use customers than by MPS Residential-with Electric Space Heating customers.
- Significantly higher customer charges are proposed to be applied to MPS residential customers than to MPS non-demand-metered small general service customers.
- A lower customer charge is proposed to be charged to L&P Residential-General Use customers than to L&P Residential-with Electric Space Heating customers.
- Proposed energy charges for both the MPS and L&P Small General Service Demand Billing rate schedules are not seasonally differentiated, even though the proposed demand charges are.

- Proposed energy charges for both the MPS and L&P Large General Service rate schedules are not seasonally differentiated, even though the proposed demand charges are.
- Certain proposed energy rates are in the range of 2.00 to 2.20 cents per kWh. These rates need to be examined to make certain that Aquila isn't proposing to provide to service at less than its avoided cost.
- Proposed MPS residential rates will reduce the proportion of total revenue collected in the summer, when compared to current rates.
- The load factor at which a 100 kW MPS customer will choose to switch from the SGS Demand Billing rate schedule to the LGS rate schedule is much too low.
- The load factor at which a 100 kW L&P customer will choose to switch from the SGS Demand Billing rate schedule to the LGS rate schedule is much too high.

(Pyatte Surrebuttal, p. 5, l.10 to p. 6, l. 12).

Aquila witness Tracy characterizes the current MPS and L&P rate structures as "sophisticated," "elegant," and "refined." (Aquila witness Tracy Rebuttal, p. 17, ll. 7-11)

The Staff believes that implementing Aquila's proposed rate designs for Aquila Networks-MPS and Aquila Networks-L&P, without extensive modifications to both the rate values and the rate structures, will amount to replacing the current rate designs for those divisions, which have not been shown to be inadequate, with one unanalyzed and inadequate rate design for both Aquila divisions. (Staff witness Pyatte Surrebuttal, p. 1, l. 29 to p.2 l, 8 and p. 12, ll. 1-4)

## <u>DETERMINATION OF RATE VALUES</u>

The seventh issue presented to the Commission, the fourth rate design issue, is: How should the appropriate rate values for each rate schedule be determined?

Each rate value on the current rate schedules for each customer class should be increased by the same percentage amount the Commission determines is appropriate to move that class closer to its cost of service.

## <u>CONCLUSION</u>

Having addressed the issues set forth in the list of issues, the Staff recommends the Commission only determine in this case the appropriate allocation factors to be used in a class cost-of-service study. This is because the results of the Staff's class cost-of-service studies it filed in Aquila's pending general electric rate case are quite different from those filed in this case and the Staff has not yet been able to determine why they are so different. If they are due to some permanent change in Aquila's cost structure, then, in the rate case, the Commission should determine the appropriate cost structure and level of costs and then require the Staff to file, for the Commission's consideration, a class cost-of-service scenario, based on the allocation factors determined in this case and the cost structure and level of costs determined in the rate case.

**WHEREFORE**, the Staff submits the foregoing as its prehearing brief in this matter.

Respectfully submitted,

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**Certificate of Service**

I hereby certify that copies of the foregoing have been mailed, hand-delivered, transmitted by facsimile or electronically mailed to all counsel of record this 4th day of November, 2005.

**/s/ Nathan Williams**