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Witness: Richard J. Kovach
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Date Testimony Prepared: May 10, 2002

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. EC-2002-1

REBUTTAL TESTIMONY

OF

RICHARD J. KOVACH

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

Exhibit No. 167
Date 7/10/02 Case No. EC-2002-1
Reporter KEM

St. Louis, Missouri
May, 2002

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REBUTTAL TESTIMONY

OF

Richard J. Kovach

CASE NO. EC-2002-1

Q. Please state your name and business address.

A. My name is Richard J. Kovach. My business address is 1901 Chouteau Avenue, St. Louis, Missouri 63103.

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

A. I am the Manager of the Rate Engineering Department at Ameren Services Company.

Q. Please describe Ameren Services Company.

A. Ameren Services is a subsidiary of Ameren Corporation which provides various administrative and technical support services for its parent and other subsidiaries including Union Electric Company, doing business as AmerenUE, (referred to herein as UE, Company or AmerenUE).

Q. Please describe your education and qualifications.

A. My educational background, work experience, current responsibilities and professional affiliations are summarized in Appendix A of my testimony.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide rebuttal comments and evidence that address various portions of the direct testimony filed by the Missouri Public Service Commission (Commission) Staff witnesses Doyle Gibbs (Customer Growth Adjustment), Alan Bax (Loss Factor Application and the Missouri Jurisdictional Demand

and Energy Allocation Factors), James Watkins (Class Revenue Requirements and Rate Design) and Janice Pyatte (Class Sales, Class Revenues and Rate Design). In addition, I have prepared an Executive Summary of the issues discussed in my testimony, including those covered in the testimony of Company witnesses James R. Pozzo and William M. Warwick. The information in the testimony of Mr. Pozzo and Mr. Warwick provides support for my testimony in the areas of class cost of service and rate design. This Executive Summary is attached hereto as Appendix B of my testimony.

Q. Have you read and are you familiar with both sets of the Staff's Direct Testimony filed by these Staff witnesses, the first of which was filed on July 2, 2001 and the second of which was filed on March 1, 2002?

A. Yes, I have read their testimony and am familiar with the areas being referenced by my rebuttal testimony. In addition, I was present at the depositions of these Staff witnesses pertaining to the issues I am addressing in my Rebuttal Testimony. In most instances, the comments presented in my testimony will be made in reference to the Staff's March 1, 2002 testimony. When I refer to any portion of their July 2, 2001 testimony, I will specifically state that to be the case.

REBUTTAL OF DIRECT TESTIMONY OF DOYLE L. GIBBS

Staff's Proposed Customer Growth Adjustment

Q. Please summarize, in general terms, the customer growth adjustment that the Staff is proposing, which is being sponsored by Mr. Gibbs.

A. Staff's proposed Revenue Adjustment S-1.5 imputes $18,068,611 of assumed additional operating revenue to the Company's test period revenue, revenue that the Company did not actually bill customers for or collect during the test year. Mr. Gibbs provides only the most cursory description of this adjustment at the bottom of page 14 of his Direct Testimony, omitting any explanation, reasoning or support for why the proposed adjustment more accurately establishes the current level of the Company's revenues in this case. This Staff adjustment simply takes the number of customers that are being served by the Company at the end of September 2001, within each customer class, and assumes that the Company was serving these customers during each month of the earlier July 2000-June 2001 test year period. The Staff's proposed customer growth adjustment assumes average levels of monthly kilowatthour usage and average monthly revenue from each of these September 2001 customers, based upon the Staff's monthly weather normalized sales and revenues of each of the Company's existing customer classes. However, while assuming normalized average use per customer and revenue per customer for their proposed "growth" customers, within each customer class, the Staff's only allowance for the additional operating costs of supplying these additional customers was average system fuel costs. In addition, while Staff witness Leon Bender incorporated additional kilowatthours for this adjustment in his production cost model, Staff witness Alan Bax failed to consider the Staff's proposed customer growth kilowatthours in the development of his Missouri jurisdictional energy allocation factor. This results in a significant portion of such energy costs being allocated to the Company's Illinois and wholesale jurisdictions, which is totally incorrect and improper. In addition, Mr. Bax also failed to consider additions to the Company's monthly coincident peak demands from the Staff's proposed customer growth adjustment. This error of omission also results in an underallocation of generation and transmission plant costs to the

Company's Missouri jurisdictional operations. I will discuss the inherent unfairness of this mismatching of customer usage, revenues and expenses at a later point in my testimony.

Q. Is the Staff's proposed customer growth adjustment an appropriate adjustment for determining the Company's overall level of revenues?

A. No, it is not an appropriate revenue adjustment, and the Commission should reject it for several reasons. First, the Staff's proposal directly violates the Commission's Order establishing July 2000-June 2001 as the test year in this case, as it imputes revenues into the test year which the Company will not receive, if at all, until after September 30, 2001, the ending date specified by the Commission for updates to the test year. Second, not only does the Staff's proposal consists of $18,068,611 in imputed "phantom" revenues from "phantom" customers based upon the "phantom" kilowatthour usage of such customers, Staff's assumed kilowatthours and revenues will not be realized by the Company during the test year, with no guarantee or probability that they will ever be fully realized. Third, other than an allowance of additional average annual fuel expense associated with their customer growth kilowatthours, Staff allowed no other direct or indirect Company costs associated with serving these proposed growth customers. Fourth, the inappropriateness of the Staff's proposed customer growth adjustment is further evidenced by the Staff's failure to include any recognition of its proposed customer growth adjustment in the development of both the Missouri jurisdictional demand and energy allocation factors.

Q. Even if the Commission were to decide to allow this customer growth adjustment proposed by the Staff, did the Staff impute a reasonable level of

operating expenses and plant investment that would be commensurate with their proposed addition of $18 million of revenues to the test year?

A. No, all information received from the Staff indicates that, with regard to operating expenses, the Staff merely allowed the Company an average level of fuel costs of approximately 1.00 cent per kilowatthour to cover the additional kilowatthours associated with their proposed customer growth adjustment. The Staff did not impute any other additional operating expenses or plant related costs associated with their proposed customer growth adjustment, within the entire time frame of the test year. As I will indicate later in my testimony, the Staff ignored several other costs associated with the Company serving new customers that should have been included under their proposal. Also, as I stated earlier, Mr. Bax did not consider such kilowatthour growth in either his Missouri jurisdictional demand or energy allocation factor development.

Q. Turning now to the first reason you gave in recommending that the Commission reject the Staff's proposed customer growth adjustment, what specific language did the Commission use in its Order establishing the ground rules to be adhered to by all of the parties in this case?

A. The Commission issued its ORDER APPROVING JOINTLY FILED REVISED PROCEDURAL SCHEDULE in this case on January 3, 2002. Paragraph 3 of page 3 of that Order, items (a) and (b), state that "the test year in this proceeding will be the twelve months ended June 30, 2001 (the Test Year)", and "the Test Year may be updated through September 30, 2001." It is very clear from this language in the Commission's Order that any additional Company operating expenses, plant investment, customer sales or revenues that are incurred, or expected to occur, after September 30, 2001 should not be included in the test year in this case. To include such items, as the Staff has done in its proposed customer growth adjustment, is a direct violation of the aforementioned provisions of the Commission's order. As the subsequent portions of my testimony will explain, the Staff's proposed customer growth adjustment imputes customer revenues into the test year that the Company will not realize until future months, if at all. Moreover, even if a portion of such customer growth revenues are realized, it will not be until after both the test year and the September 30, 2001 date specified by the Commission for updating information in this case.

Q. Turning now to the second reason you gave in recommending that the Commission reject the Staff's proposed customer growth adjustment, please illustrate why it is appropriate to refer to the $18 million of revenues associated with this proposed Staff adjustment as phantom revenues.

A. Using the Company's residential customer class as an illustration, the Company's actual monthly test year customer growth and the Staff's proposed imputed customer growth adjustment are illustrated in the bar chart attached hereto as Schedule 1-1 of my testimony. The clear bars in this chart represent the Company's actual test year residential customers. This data shows that the Staff's proposed customer growth adjustment is arrived at by artificially increasing the Company's actual test year level of residential customers up to the September 30, 2001 level of customers (the totally cross-hatched bar on the far right of the chart) during each month of the test year. The shaded (phantom) area above each of the clear bars in Schedule 1-1 indicates the number of the residential customers imputed into the test year by the Staff's proposed customer growth adjustment.

Q. Does the result of the Staff's proposed customer growth adjustment distort the Company's normal customer growth pattern by artificially replacing this pattern with a levelized number of customers that did not actually exist at any time during the test year?

A. Yes, the Staff's proposed customer growth adjustment inappropriately creates a distortion of the Company's actual test year customers and normal patterns of customer growth (the clear bars on my Schedule 1-1). This distortion of the actual pattern of growth in the Company's number of monthly customers, to the levelized number of phantom monthly customers developed under the Staff's customer growth proposal, is clearly a deviation from historic reality. The portion of the clear bars above the June 2000 customer horizontal line in my Schedule 1-1 illustrates the pattern of normal monthly customer growth actually experienced by the Company during the test year established for this case. Clearly, the Staff's proposed imputation of additional phantom customers, resulting in total additional phantom Company revenues of $18 million, is a significant reach beyond reality and the test year specifications established by the Commission for this case.

Q. Did the Staff adjust the number of customers in each of the Company's non-residential customer classes in a similar manner, as a part of their proposed customer growth adjustment?

A. Yes, with the exception of the lighting class, the Staff also followed this procedure for adjusting for customer growth within each of the Company's other non-residential customer classes, although Ms. Pyatte indicated that she examined the customers in the Large Primary Service Rate class on an individual customer basis. The data on Schedule 1-1 indicates how the Staff's proposed customer growth adjustment belies reality by assuming a customer growth pattern for the Company that is totally out of sync with the actual customer growth normally experienced by the Company, on a year-in and year-out basis, and within the confines of any twelve month period, or historic test year.

Q. When will the Company theoretically first realize a full twelve months of revenue from the level of customers it was serving as of September 30, 2001?

A. Theoretically, the Company will not first realize a full twelve months of revenue from the total number of its September 30, 2001 level of customers until the end of September 2002, if at all. September 2002 is more than two years (27 months) after the beginning of the July 2000-June 2001 test year in this case, and 15 months beyond the end of the test year. For example, a new customer that began receiving service sometime in September 2001, will not receive and be billed for a full twelve months of service by the Company until the end of the month of September 2002 (October 2001 would be the first full month of service, November 2001, the second full month, etc., until reaching September 2002). Thus, virtually all of the first twelve months of sales, revenues and expenses associated with serving a new September 2001 customer would be outside of the established test year and beyond the update period specified by the Commission for this case.

Q. When will the Company theoretically first realize a full twelve months of revenue from new customers initiating service with the Company in July 2000, which is the first month of the test year?

A. In theory, the Company will realize a full twelve month period of revenues from a new July 2000 customer over the period from August 2000-July 2001, eleven months of which would be fully reflected in the test year specified in this case. A similar pattern would occur for new customers gained in subsequent months of the test year, i.e., new customers in August 2000 would not result in a full twelve month period of revenues until the September 2000-August 2001 period, ten months of which are within the test year. Similarly, new customers that begin service in later months of the test year will incur a greater proportion of their first twelve months of electric bills beyond both the test year and the September 30, 2001 date established by the Commission for updates in this case.

Q. What do the latter comments illustrate regarding the Company's normal pattern of acquiring new customers and realizing actual revenues from them?

A. The point of this discussion is that normal customer growth is an inherent part of every twelve month period, including test years, but that none of the phantom revenues associated with the Staff's proposed customer growth adjustment will actually be realized during the Commission's ordered test year or even as of the update period in this case. The inclusion of such an adjustment in establishing the Company's revenue requirements in this case is, thus, a clear violation of the Commission's ordered test year specifications.

Q. Your previous comments regarding the Company's realization of additional customers, kilowatthours and revenues, associated with the Staff's

proposed customer growth adjustment, were described as "theoretical." Why is this qualification necessary?

A. The examples I described regarding the time periods over which new customers would eventually provide a full twelve month period of kilowatthours and revenue are theoretical, in that they are prospective in nature and, therefore, not totally certain. For example, the Company loses some customers month in and month out, even as it is also gaining a larger number of new customers. In the residential sector, interest rates affect the level of consumer spending and borrowing which, in turn, affects the home building and automobile sectors, as well as residual demands for additional home furnishings and major appliances. In the non-residential classes, some of the Company's commercial and industrial customers go out of business from time to time. Moreover, the electrical usage of such commercial and industrial customers that continue ongoing operations will vary as these customers are susceptible to the ups and downs of the general economy as it affects the economic sectors associated with their line of products or services.

Q. Are you aware of any major business failures or announced plant shutdowns in the AmerenUE service area over the past several years?

A. Yes, I am. In the commercial sector, the National Food's super market chain, with about two dozen stores in the area, was sold to a competitor and several of their locations subsequently closed. In addition, both the Venture and K-Mart department stores declared bankruptcy. Venture closed all of their stores and is now totally out of business. K-Mart, while attempting to restructure during bankruptcy, has closed several of their stores. In the industrial sector, the A. P. Green brick manufacturing plant in

Mexico, Missouri is scheduled to close in April 2002 and the Ford Motor Company has announced the intended closing of their Hazelwood, Missouri manufacturing plant in the near term. Other firms, whose identities should not be disclosed, are in the midst of either environmental, market or overall financial difficulties and may not survive as ongoing entities. These uncertainties regarding both current and future customers are real, but unpredictable, and it is also likely that there have been a number of similar events affecting smaller commercial and industrial customers of which I am unaware. In fact, in his discussion of uncollectible expenses on page 35 of his testimony, Mr. Gibbs references the Company's larger write-offs, a slower economy and an increase in bankruptcies.

Q. Earlier you stated that the Staff determined its usage and revenues for their phantom growth customers based upon averages of the weather normalized usage and revenues of the Company's existing customer base. Why might this result in an overstatement of the usage and revenues for the additional customers added by the Company since July 2000 and up to September 30, 2001?

A. In the case of new home and apartment construction, newer housing stock is being constructed to attain higher overall energy efficiency, including improved insulation levels and high efficiency heating and air conditioning appliances. As the Staff ignored these factors and merely used existing customer averages as a proxy for the usage and revenue of the customers included in their proposed customer growth adjustment, the Staff's usage and revenues of such customers are likely to be overstated. These same comments are equally applicable to the Company's newer small commercial customers. New larger commercial and industrial customers are also utilizing offices and plants operating with higher efficiency HVAC systems, lighting systems and manufacturing systems. For all of these reasons, the Staff's use of the average usage and revenues of the existing customers in these rate classes is likely to overstate the usage and revenues that can be expected from new customers.

Q. Is there yet an additional reason that the Staff's proposed customer growth adjustment likely overstated the projected usage and related revenues for any new or additional large commercial and industrial customers added by the Company between June 2000 and September 30, 2001?

A. Yes, there is an additional reason why it is not appropriate to calculate a growth adjustment for the Company's larger commercial and industrial customers on the basis of average usage and revenues for the Company's existing customers. The Company's existing large commercial and industrial customer base currently consists of the headquarters of several major corporations, a new federal courts building, manufacturing plants of the big three automakers, several major chemical plants, several major cement plants, a major aircraft manufacturing plant, a major brewery, several major universities, several medical complexes, an international airport and other many other major manufacturing customers. It is very unlikely that the operations, electrical usage and revenues of these existing customers, that are included in the Staff's averages for these customer classes, would be duplicated by any new customers moving into the Company's service area. As these customers are unique and among the Company's larger electric customers, including them in any average usage and revenues as a proxy for the new customers in the Staff's proposed customer growth adjustment would obviously overstate any growth that might reasonably be anticipated from such customers.

Q. Turning now to your third reason in recommending that the Commission reject the Staff's proposed customer growth adjustment, why is the Staff's proposed allowance for average expenses only and no additional plant related costs, an inadequate representation of the true costs associated with serving additional customers?

A. The Staff's proposed allowance for the additional fuel costs associated with their customer growth adjustment is woefully inadequate. In addition, other operating expenses that should have been included by the Staff were totally ignored. The areas in which the Staff cost allowances for new customers are deficient are: a) the allowed level of fuel expense for customer growth is significantly understated; b) other direct costs of serving new customers, including such obvious items as meter reading, billing and postage expenses were completely ignored; and c) the additional customer demands which inherently accompany customer growth were also completely ignored by the Staff.

Q. What level of fuel expense did the Staff allow for the Company's cost of supplying the additional kilowatthours associated with their proposed customer growth adjustment?

A. Mr. Gibbs could not actually answer that question at his first deposition (Gibbs Deposition Transcript, page 49, lines 19-20). The Company requested that information from the Staff, and the information provided indicated that the level of fuel expense allowed by the Staff as an offset to their proposed customer growth adjustment was approximately 1.00 cent per kilowatthour. Staff allowed no other additional operating expenses of any type as a part of their customer growth adjustment. Even considering this Staff limitation of including fuel expenses only, with which I disagree, this level of unit fuel or energy cost is only representative of an annual average of the Company's total overall unit energy costs from all of its production sources, which include coal, gas, oil, nuclear, hydro, pumped storage and interchange sources. As I will describe later in my testimony, it is totally inappropriate to use the Company's annual average energy costs for the purpose of "expensing," or determining the cost of incremental additions or subtractions of customers and kilowatthour sales to or from the Company's generation system.

Q. What is the financial impact of the Staff "expensing" its incremental growth adjustment kilowatthours based upon this average energy cost of approximately 1.00 cents per kilowatthour?

A. At this level of fuel cost, the 287,385,000 kilowatthours associated with the Staff's customer growth adjustment would have resulted in an operating expense of approximately $3.1 million (including average system losses), as compared with the additional imputed revenues of $18.1 million associated with this Staff adjustment.

Q. Is an operating income margin of $15.0 million, which is the Staff's proposed additional customer growth adjustment revenue of $18.1 million less their proposed additional fuel cost of approximately $3.1 million, a realistic operating result?

A. Absolutely not. This data would indicate that the Company's operating income margin is some 83% of revenues ($15.0/$18.1), which is totally unrealistic. In fact, even the Staff's own Income Statement on its Schedule 9 suggests a Company operating margin of 46% [($2,152-$1,152)/$2,152] of total revenues after subtraction of total O&M expenses. After consideration of the total O&M expenses, depreciation, amortization, taxes-other and income taxes, the Staff's Schedule 9 shows the Company's operating income margin as 23% ($505/$2,152). Thus, even when compared against the Staff's own numbers the limited expenses allowed by the Staff as a part of their proposed customer growth adjustment suggests a totally unrealistic operating income margin.

Q. Why are incremental fuel costs more appropriate for determining the true cost of the additional kilowatthours imputed upon the Company's generation system by the Staff's proposed customer growth adjustment?

A. The Company meets the requirements of its hourly system peak loads through the economic dispatch of all of its system resources, which include owned generation as well as bulk power sources available through various system interchange arrangements. This economic dispatch of power sources generally utilizes the lowest cost generating units or sources first, then incrementally uses each next lowest cost source available until the system load is met for a given time period. Under such a system of economic dispatch the last increment of system load served is generally that served at the highest cost (but the next lowest cost available) source of generation. The Staff's proposed customer growth adjustment is incremental in nature. Therefore, to the extent that the Staff's proposed customer growth adjustment imputes additional kilowatthours, or load requirements which did not actually exist during the test year on the Company's system, this additional incremental load cannot be served at average fuel costs but, rather, would be supplied at the Company's higher incremental fuel costs. The Staff should have attempted to evaluate this cost on an incremental load basis using their production cost model, to obtain a more accurate estimate of the true cost of providing the additional kilowatthours associated with their proposed customer growth adjustment, but they did not do so.

Q. Did the Company evaluate the fuel expense that results from the Staff's imputed customer growth kilowatthours on an incremental cost basis?

A. Yes, the Company determined the incremental costs for the customers in the Staff's proposed customer growth adjustment to be 2.13 cents per kilowatthour during the test year, which is more that 110% above the Staff's average cost figure of 1.00 cent per kilowatthour. Based upon this cost of 2.13 cents, the additional fuel expensed for the 287,385,000 kilowatthours associated with the Staff's proposed customer growth adjustment would be approximately $6.1 million, instead of the $2.8 million allowed by the Staff.

Q. You also indicated earlier that the Staff completely ignored other direct costs of serving new customers. What are the more obvious operating costs associated with serving new customers that the Staff has failed to include as a part of their proposed customer growth adjustment?

A. The most obvious direct expenses associated with serving additional customers that the Staff failed to include are the additional meter reading expenses which are, by contract, based upon a monthly reading charge per meter. Other obvious direct expenses that Staff failed to include are the costs of generating additional bills, postage and handling, and customer accounts expenses. Other less direct but obvious and real expenses that were omitted are allowances for the additional customer call center, credit and collection expenses and distribution operating expenses associated with serving a greater number of customers. While some of these expenses may be more difficult to quantify than others, Mr. Gibbs acknowledged that some allowance for such costs should have been included by the Staff in setting the level of revenues for the Company in this case (Gibbs Deposition Transcript, page 45, line 24, page 49, line 4). However, the Staff made no allowance for such costs.

Q. As indicated earlier in your testimony, in proposing his customer growth adjustment, Mr. Gibbs included total monthly revenues per customer, but limited added expenses only to average fuel costs. Should he also have added the current level of all other non-fuel costs associated with serving such customers?

A. Besides determining the fuel cost of such imputed growth on an incremental cost basis, as I indicated earlier, Mr. Gibbs should have also added a full complement of the other non-fuel costs to his adjustment of the Company's expenses in this case. In that way he could have at least attempted to maintain some level of fairness and consistency in the proper matching of the customer growth in usage, revenues and costs during the test year.

Q. Earlier in your testimony you indicated that the Staff's proposed customer growth adjustment also completely ignored the additional customer demands which inherently accompany customer growth. What are the fixed, or demand-related, costs that are also included in the Company's rates?

A. As I will discuss later in my testimony, the costs included in the Company's rates are normally classified as customer-related, energy-related (kilowatthours) and demand-related (kilowatts) costs. The meter reading, billing and postage costs discussed earlier are classified as customer-related costs, while fuel and other variable production operating expenses are classed as energy-related costs.

Demand-related costs, sometimes referred to as fixed, or capacity related costs, are the costs of plant and equipment incurred in meeting the customer's use of electricity during times of maximum or peak period consumption. The total costs classified into the latter demand related category constitute approximately 60 % of the Company's total annual costs recovered through its retail rates in Missouri.

Q. Turning now to your fourth reason in recommending that the Commission reject the Staff's customer growth adjustment, what is your basis for stating that the Staff's proposed customer growth adjustment was not reflected in the Missouri jurisdictional demand and energy allocation factors developed by Mr. Bax?

A. Only actual Company monthly jurisdictional demands are displayed on Mr. Bax's Schedule 5, where he developed the Missouri jurisdictional demand allocation factor. Schedule 5 indicates no adjustment in such demands for the Staff's proposed customer growth adjustment or any other Staff adjustment. Referring to Mr. Bax's Schedule 6, where he developed the Missouri jurisdictional energy allocation factor, his starting point was actual Company kilowatthour sales data. In his footnotes on Schedule 6, however, Mr. Bax describes two kilowatthour adjustments that he did make to this data. The first was to reflect the Staff's proposed weather normalization adjustment. The second was to reflect the Company's loss of wholesale bulk power sales to the City of Rolla, Missouri. Although the monthly demands of Rolla were available to Mr. Bax, he did not choose to use them as an accompanying adjustment to the demands he used in calculating the Missouri jurisdictional demand allocation factor in his Schedule 5. Later in my testimony, in my rebuttal to Mr. Bax's testimony, I will discuss various other adjustments and corrections that he should make in the calculation of the Missouri jurisdictional demand and energy allocation factors.

Q. Did other members of the Staff agree that the Company's monthly system peak demands would increase as a result of the proposed customer growth adjustment?

A. Staff witnesses Gibbs, Pyatte and Watkins all agreed in their initial depositions taken last fall that the Company's monthly demands would increase as a result of customer growth (Gibbs Deposition Transcript page 47, line 10 through page 48, line 7, Pyatte Deposition Transcript pages 45, line 21 through 48, line 9, Watkins Deposition Transcript pages 107, line 3 through 109, line 15).

Q. What additional kilowatt demands would the Staff's proposed customer growth adjustment impose on the Company?

A. Additional customers on the system would result in higher individual kilowatt demands on the Company's local distribution system, which must be sized to meet individual customer demands on an instantaneous basis. Moving away from the distribution system to the Company's power plants, additional customers would also add to the hourly coincident system demands that must be met with hourly generation by the Company's portfolio of power sources. Individual customer demands, which do not all reach their maximum level during the same hour each month, are therefore often referred to as non-coincident demands. The portions of these individual customer demands which are present during the hour of each month when the Company's total system monthly peak is established are referred to as coincident demands, as they and the demands of all other customers are coincident with and aggregate into the Company's maximum monthly system peaks. The difference between individual customer maximum peaks and coincident peaks results from the diversity of electrical use among customers. The ratio of the non-coincident customer peaks to the coincident customer peaks is referred to as the diversity factor.

Q. Would the consideration of additional customer coincident demands also have had an impact upon the Company's monthly system coincident peak demands and the resulting Missouri jurisdictional allocation factor?

A. Yes, they would. As with the fuel costs mentioned earlier, additional customer demands would add to the Company's monthly coincident system peaks, which would increase the Missouri jurisdictional allocation factor used to allocate the Company's production and transmission plant costs to Missouri. The failure of the Staff to consider such customer demands as a part of its proposed customer growth adjustment results in the Staff understating the Missouri jurisdictional allocation factor, thereby under allocating the Company's investment in production and transmission plant to Missouri. As with other costs that the Staff failed to consider, this results in yet another understatement of the level of the Company's total costs that should be reflected in the Company's Missouri retail rates. I will provide additional comments on this omission by the Staff in my rebuttal comments directed to the testimony of Mr. Bax.

Q. Can the Company continue to add customers if the only additional expenses it is allowed in its rates to serve such customers are average system fuel costs, the only expense allowed by the Staff as a part of its proposed customer growth adjustment?

A. No because the financial constraint associated with the Staff's growth adjustment, of allowing the Company to recover only average system fuel expenses to serve its additional customers, is both unrealistic and totally inequitable to the Company. Moreover, Staff's failure to include the additional direct operating expenses and allocated demand related costs associated with serving additional customers results in the totally unrealistic operating income margin of 83%, referred to earlier in my testimony.

Q. What are the real additional costs to the Company of supplying additional customers?

A. The Company's intermediate-term and long-term costs of serving additional customers are best reflected by the sum of the various functional components embedded within the Company's current class rate structures, which are comprised of the total cost of providing service to its customers. These costs include all operating and maintenance expenses, depreciation, taxes and a fair return on net plant investment.

Q. Had the Staff included all of the Company's additional operating expenses and other costs in addition to fuel costs, as a part of its proposed customer growth adjustment, would this make such an adjustment acceptable to the Company?

A. No, because if the Staff realistically and accurately reflected all of the Company's embedded costs, as well as the additional revenues associated with their customer growth adjustment, the costs and the revenues would, theoretically, come close to matching each other, and there would be no need for such an adjustment. As indicated earlier in my testimony, however, the impact of the Staff's proposed customer growth adjustment is to create phantom revenues associated with the Company's September 2001 customers that would not be actually realized by the Company until well beyond the cutoff for test year updates (September 30, 2001) established by the Commission for this case, if at all. Staff's proposal inappropriately shifts such phantom revenues into the test year in this case, which began 15 months earlier in July 2000, while omitting most of the associated costs of providing such additional service. The Staff's proposed customer growth adjustment, which includes the total amount of the incremental revenues which might be realized as a result of the additional customers, but only minimal additional average fuel costs, is extremely unrealistic and a far cry from the proper matching of costs and revenues, which should always be the objective in setting fair and equitable rate levels. Shifting sales and revenues into a test year, which will not exist or be realized until after the test year, if at all, without the appropriate consideration and adjustment of all relevant costs associated with such sales and revenues, is totally unjustified and unfair.

Q. Was any customer growth adjustment, similar to that proposed by the Staff in this case, employed in any of the six "test year" periods that were a part of the Missouri alternative regulation plans in which the Company previously participated?

A. No, because those plans utilized actual test periods that reflected true and actual Company operations, with only a very few pre-specified accounting adjustments. During these two plans, which ran for six consecutive years from July 1995-June 2001, the Company's actual customers, sales, and accompanying revenues within each of these plan operating years were considered on an as-incurred basis, with no such adjustment.

Q. If a Staff customer growth adjustment similar to that being proposed in this case would have been a part of any one of the twelve month "test" periods in

the alternative regulation plans, how would it have impacted the results of the formulated calculations under those plans?

A. This proposed Staff customer growth adjustment, in effect, transfers full end of period customers and their associated revenue (and only average fuel expense) between subsequent and prior twelve month time periods. Thus, under an alternate regulation plan format involving several consecutive twelve month time periods, the prior period receiving the revenue and the minimal offsetting fuel expense would experience increased (but unreal, or phantom) earnings equivalent to the difference between such revenue and fuel expense (the unrealistic 83% operating margin referred to earlier). On the other hand, the subsequent period from which such revenue and fuel expense was transferred would, under the same calculations, experience a decline in earnings of an equivalent (but unreal, or phantom) amount. This assumes, of course, that these inappropriate transfers are not later reversed (or ignored), when the subsequent period referred to earlier has become the prior period due to the passage of time.

Q. Assume that either of the alternative regulation plans had continued into the future on an indefinite basis and the Staff had proposed a comparable customer growth adjustment for each and every "test" period within this plan. Under this assumption, what would be the impact of a continuous Staff customer growth proposal, comparable to that being proposed in this case?

A. Under these assumptions the Staff's proposed customer growth adjustment would be unnecessary, as the Company's actual customer growth would be automatically accounted for during each successive twelve month update period. If such an adjustment was made, however, it would in effect, permanently reduce the Company's annual earnings for each "test" period by an amount equal to the difference between the revenue and fuel expense being transferred from one "test" period to the immediately preceding "test" period (the unrealistic 83% income margin). These phantom earnings would artificially inflate the Company's net operating income in each twelve month period, thereby prohibiting the Company from actually earning the rate of return authorized by the Commission. In effect, this Staff proposal results in a $15.0 million "take-away" from the Company, based upon the information presented in the Staff's case.

Summary of the Company's Comments on Staff's Proposed Customer Growth Adjustment

Q. Please summarize your position regarding the Staff's proposed customer growth adjustment.

A. The proposed Staff customer growth adjustment should be rejected by the Commission. The proposal violates the test year and updating provisions of the Commission's Order in this case by creating uncertain and speculative phantom test year customers, kilowatthours and revenues which are not applicable to the test year, or the update period. Even if such an adjustment is permitted, the Staff's adjustment of kilowatthours and revenues are overstated as they were based upon an average of the Company's existing customer base, and not the new or additional customers the Staff's adjustment is adding. Moreover, the additional fuel expenses proposed by the Staff as a companion to its proposed customer growth adjustment were determined in an inappropriate manner that significantly understates the additional fuel costs the Company would incur in supplying such growth. In addition, other costs relevant to serving customer growth were ignored altogether by Staff, including such obvious costs such as meter reading, billing and postage, as well as the impact of the Staff's adjustment upon the Missouri jurisdictional demand allocation factor, which allocates a significant portion of the Company's total production and transmission plant costs to Missouri. It is clear that when applying this Staff proposal to several consecutive annual test years it has the effect of simply imputing phantom revenues in establishing the Company's overall level of revenues and rates. However, in actuality these revenues were never realized by the Company during the test year or the update period, and therefore cannot and should not be utilized for establishing Company revenue and rate levels for the test period. In addition, as will be specifically illustrated in my rebuttal to the Missouri jurisdictional demand and energy allocation factors developed by Mr. Bax, the Staff totally ignored their proposed customer growth adjustment in the development of these factors, which has the effect of understating the Missouri jurisdictional demand and energy allocation factors, while increasing and overstating these factors for the Company's Illinois and Missouri wholesale jurisdictions. For all of the above reasons, this proposed Staff customer growth adjustment is woefully and significantly deficient as a revenue requirement determination tool and should not be accepted by the Commission.

REBUTTAL OF DIRECT TESTIMONY OF ALAN J. BAX

Staff's Proposed Loss Adjustment Factor

Q. Turning now to the direct testimony of Mr. Bax, how would you characterize the system energy loss factor that was calculated by Mr. Bax?

A. The loss factor of .0658, or 6.58%, calculated by Mr. Bax and indicated on page 2 of his testimony, is a representation of the average AmerenUE system energy losses for the twelve month period ending September 2001, excluding Company usage. Mr. Bax calculates this loss factor as a percentage of his determination of the Company's annual Net System Input (kWh) that appears on Schedule 1 of his testimony. These annual energy losses can also be calculated as a percentage of annual Total Sales (kWh), which also appear on his Schedule 1. This same level of annual energy losses as a percentage of annual sales is .0705, or 7.05%. The mathematical calculation of both of these loss factors is correct based upon the data in Mr. Bax's Schedule 1. However, they must be applied to the appropriate base used in their calculation, either system input or system sales, respectively, in order to arrive at accurate and consistent calculations of system losses.

Q. Are there basic inconsistencies in the time period used by Mr. Bax in making this calculation and the time periods he and other Staff members used in making various other kilowatthour based calculations?

A. Yes, there are basic inconsistencies among Staff members and even between various schedules prepared by Mr. Bax. For example, he based the kilowatthour calculations in his Schedule 1 on the twelve months ending September 2001, while he based the kilowatthour calculations in his Schedule 6 on the twelve months ending June 2001. In all of the other Staff schedules containing calculations involving kilowatthours and revenues, i.e., Ms. Mantle's and Ms. Pyatte's schedules, the twelve month period ending June 2001 was used.

Q. Regardless of these inconsistencies in data periods, does the loss factor calculation in Mr. Bax's Schedule represent a combined average annual loss factor for all of the AmerenUE jurisdictions?

A. Yes because this data represents the kilowatthour usage of all of the Company's customers in both Missouri and Illinois, and the usage of its Missouri wholesale customers.

Q. As an annual average, is the loss adjustment factor calculated by Mr. Bax representative of the Company's losses during all hours of a given year?

A. No because system losses will generally be higher during the hours and months of the year when the Company is experiencing high demands, or peak loads, than during moderate or low demand conditions. In fact, the relationship of system losses to the Company's peak load hours is non-linear, i.e., losses become proportionately larger as system demands increase. In mathematical terms, the level of losses will actually vary with the square of the Company's system demands, rather than just increasing in linear proportion to these demands.

Q. Is the loss adjustment factor proposed by Mr. Bax representative of the losses the Company incurs in providing service to any one of the Company's various individual customer rate classes?

A. No, as I indicated above, the factor that Mr. Bax has calculated is an average annual system loss factor. As such, this annual factor reflects the composite mix of all of the Company's individual customer class usage profiles, voltage levels and loss factors within all of the Company's retail and wholesale regulatory jurisdictions referenced earlier. These individual customer profiles vary considerably throughout the year, both between and within the different customer classes and jurisdictions served by the Company. However, even setting variations in usage during different time periods aside, the annual losses incurred by the Company in serving each of its different customer classes vary significantly.

Q, Please elaborate on how system losses vary among customer classes, even on an annual basis.

A. Residential customers generally receive their service from the Company at 120 to 240 volts and small general service customers at a range of from 120 to 480 volts. These are the lowest voltage levels on the Company's system, requiring several transformations, or voltage step-downs, and the transmission and distribution of the electricity over various sets of high and lower voltage conductors and cables in order to supply these customers from the power plants that generate their electricity. Each of these voltage reductions, and the transmission and distribution of electricity over the many miles of conductors and cables necessary to enable the Company to serve these low voltage customers are the source of such losses.

Q. Do these losses add to the amount of electricity that must be generated to meet each customer's metered usage requirements?

A. Yes, these losses require a higher amount of electricity to be generated at the power plants to enable the Company to provide the total amount of electricity ultimately required to be delivered to the meters of the customers being served.

Q. What portion of these transmission and distribution facilities are used in providing the electrical requirements of the larger commercial and industrial customers?

A. In contrast to the customers served at low voltage levels, large commercial and industrial customers are supplied at significantly higher voltages ranging from 4,160 to 34,500 volts. As a result, such customers are served by the Company with fewer voltage transformations and without the additional low voltage equipment required for the smaller customers. This results in the Company incurring a lower level of losses in supplying the electrical requirements of the high voltage customers.

Q. Generally, how do the average losses of the different customer classes served by the Company vary based upon the voltage level at which their service is supplied?

A. In broad terms, the average losses incurred by the Company in supplying the low voltage residential and general service customers are approximately 10%. The Company's losses incurred in serving 4,160-12,470 volt customers are about 6% and its losses incurred in serving 34,500 volt customers are about 5%. These factors indicate that the Company must generate about 110 kilowatthours to deliver 100 kilowatthours to a residential customer's meter, whereas only 105-106 kilowatthours must be generated by the Company to deliver the same 100 kilowatthours to the meters of the higher voltage customers.

Q. Is the Staff aware of these differences in customer class loss factors based upon different service voltages?

A. Yes, they are. Mr. Bax acknowledged these differences during his deposition taken on November 28, 2001. (Bax Deposition Transcript, pages 28-34). He nevertheless calculated only a single average annual system loss factor as a part of his testimony and provided this single average system loss factor to Staff witness Lena M. Mantle.

Q. What is your general understanding of how Ms. Mantle used the single average annual loss factor provided to her by Mr. Bax?

A. On page 8 of her testimony, Ms. Mantle refers to the use of the loss factor provided by Mr. Bax in order to arrive at the hourly net system loads. Staff witness Leon Bender then used these hourly system loads, or demands, as inputs to the Staff's production cost model to develop a normalized level of annual fuel expense for the Company. This same model was also used to determine the production cost associated with other adjustments made by the Staff that involved changes in kilowatthours.

Q. Was this production cost model used in arriving at the Staff's fuel cost allowance associated with the proposed customer growth adjustment sponsored by Staff witness Doyle Gibbs?

A. Yes, as indicated in the testimony of Staff witness Lena Mantle, the Staff's adjusted and normalized kilowatthour sales summarized in Schedule 2 of Staff witness Janice Pyatte's testimony, was provided to Staff witness Leon Bender to use as input to his production cost model. Information subsequently provided to me by Ms. Mantle and Mr. Greg Meyer confirmed that Ms. Pyatte's Schedule 2 data was Mr. Bender's input for the Missouri jurisdictional kilowatthours, after adjustment for average annual system losses.

Q. Based upon your earlier comments, does the Staff's failure to consider both the higher level of losses during peak demand periods, as well as the

differences in customer class losses, result in an understatement of the Company's fuel costs by the Staff's production cost model?

A. Yes, both of these factors result in an understatement of the Company's fuel costs. As I indicated earlier, Mr. Bax is well aware of the fact that peak load losses and low voltage customer losses are higher than the average annual energy loss factor which he calculated and made available for use by other Staff witnesses. As virtually the entire customer growth adjustment sponsored by Mr. Gibbs was associated with residential and general service rate customers, which are served at the Company's lowest system voltage levels, it follows that a higher loss factor approximating 10% of metered kilowatthours should have been used by the Staff for calculating the fuel costs associated with their proposed customer growth adjustment. In addition, as these customer classes would also tend to have higher demands during the Company's peak summer season, due primarily to the use of air conditioning, it also follows that the hourly loads in the Staff's production cost model should have been increased to account for the additional increase in losses during such periods. The Staff's failure to properly consider these factors results in yet another understatement of the production costs required to serve the customers added by the Staff's proposed customer growth adjustment.

Q. Is this understatement of production costs by the Staff in addition to that which you pointed out earlier, regarding the use of average fuel costs, in your rebuttal of Mr. Gibbs?

A. Yes, my rebuttal comments to the testimony of Mr. Bax are addressing yet another understatement of fuel or production costs associated with the Staff's proposed customer growth adjustment. In rebuttal to Mr. Bax, I point out that the Staff's use of an average annual loss factor, which ignores the higher peak season loss factors attributable to the period where the Staff has imputed the major portion of their growth, and which also ignore the lower voltage level (higher loss level) attributable to the majority of the customers imputed by their proposed customer growth adjustment, also tends to understate the Company's fuel costs. My earlier rebuttal to Mr. Gibbs in this area was based upon the Staff's use of the lower average fuel costs rather than the higher incremental fuel costs associated with their proposed customer growth adjustment.

Staff's Proposed Missouri Jurisdictional Demand Allocation Factor

Q. Moving on to Mr. Bax's determination of the Missouri jurisdictional demand allocation factor, what is the purpose of developing this factor?

A. The jurisdictional demand allocation factors are used by the Staff to allocate the Company's investment in production and transmission plant, and associated fixed operating and maintenance expenses, to each of the Company's jurisdictions. The data Mr. Bax used for this determination is that shown on his Schedule 5, based upon the twelve month period ending September 2001. The data contained in this schedule are the twelve monthly peak kilowatt demands of each of the Company's Missouri and Illinois retail jurisdictions and the Company's Missouri wholesale jurisdiction.

Q. Is the data on Mr. Bax's Schedule 5 the Company's actual jurisdictional monthly demands for the time period represented?

A. Yes, this data represents actual Company demands. Mr. Bax's testimony indicates that he obtained such data from various Company sources. Comparable

Company monthly demand data is contained in different forms and for various time periods in Schedules 2-5 of Mr. Bax's testimony.

Q. As the source of all of this data is actual Company monthly demand data, was this data adjusted or altered in any way by Mr. Bax in his determination of the Missouri jurisdictional demand allocation factor?

A. This appears to be actual Company demand data and there was no mention or indication in Mr. Bax's testimony, or in his deposition, of his having adjusted this data.

Q. Would the additional customers imputed by the Staff's proposed customer growth adjustment have created or resulted in additional customer demands at the time of the Company's monthly system peaks?

A. Yes, as I also stated in my earlier rebuttal of Mr. Gibbs, the additional customers imputed to the test year by the Staff's proposed customer growth adjustment would create additional system peak demands.

Q. Was any growth in customer demands, associated with the Staff's proposed customer growth adjustment, considered by Mr. Bax?

A. As I also indicated earlier, no change in customer demands, or in the Company's monthly peak demands, was indicated in the testimony of Mr. Bax. Moreover, at his deposition on April 24, 2002, he was specifically asked if he considered any additional demands associated with the Staff's proposed customer growth adjustment. He indicated at that time that he had not done so (Bax Deposition Transcript, page 15, line 23 through page 16, line 2; page 23, lines 10-17). Mr. Bax erroneously assumed that the additional customers imputed into the test year, as a result of the Staff's proposed customer growth adjustment, would result in additional kilowatthours provided and revenues being realized by the Company, but without any accompanying customer demands related to the additional electricity consumed by such customers.

Q. While Mr. Bax made no adjustments to the Company's demands to reflect the Staff's proposed customer growth adjustment in his Schedule 5, did he nevertheless make kilowatthour adjustments to reflect the Staff's weather adjustment and to remove the City of Rolla from the Missouri wholesale column in his Schedule 6?

A. Yes, he reflected the kilowatthour sales associated with the Staff's weather adjustment for each of the Company's regulatory jurisdictions indicated on his Schedule 6. He also deducted the kilowatthour sales to the City of Rolla for the months of July 2000-December 2000, as Rolla's energy requirements were no longer served by the Company on and after January 1, 2001.

Q. In making this kilowatthour deduction for Rolla in the calculation of the variable allocation factor in his Schedule 6, should Mr. Bax have followed through with a similar adjustment for Rolla in the determination of his recommended jurisdictional demand allocation factor in his Schedule 5?

A. Yes, he certainly should have followed through with this adjustment to be consistent with all of his work in this case. Although Mr. Bax made some adjustments to the Company's kilowatthour data in his Schedule 6, he made no accompanying adjustments to the Company's demand data in his Schedule 5. This is totally improper and inconsistent, and results in an incorrect Missouri jurisdictional demand allocation factor.

Q. If additional customer demands associated with Rolla and the Staff's proposed customer growth adjustment had been included by Mr. Bax in the data on his Schedule 5, would this have increased the Missouri jurisdictional demand allocation factor?

A. Yes, the Missouri jurisdictional demand allocation factor would have increased had Mr. Bax made the appropriate adjustments in the Company's monthly demands for both the Missouri retail and wholesale jurisdictions. This occurs because Missouri retail demands should be increased to reflect the Staff's imputed customer growth, and Missouri wholesale demands should be decreased due to the removal of the Rolla demands for a portion of the test year. These changes would have been particularly noticeable during the Company's summer peak months (the months of maximum adjustment for both Rolla and the customer growth under the Staff's proposal) when such demands and their associated losses would have been at or near their maximums.

Q. Is there another adjustment that should be made to the demands in Mr. Bax's Schedule 5 to reflect a significant customer loss in the Company's Illinois jurisdiction?

A. Yes, while Mr. Bax may not have been made aware of it by Mr. Gibbs (who reviewed the Company's uncollectible expenses), Laclede Steel Company in Alton, Illinois filed for bankruptcy during the early part of the test year. This resulted in a sizable reduction in Illinois jurisdictional demands after December 2000, which have never returned to the system. Thus, the monthly demands attributed to Laclede Steel during the July-December 2000 period should be deducted from the Illinois column in Mr. Bax's Schedule 5 to reflect this permanent change in customer usage in Illinois.

Q. Have you estimated the changes in the Company's monthly system peak demands that should have been considered by the Staff as a part of their proposed customer growth adjustment and the loss of both Rolla and Laclede Steel?

A. Yes, I have. Using the Company's load research data, I have estimated the demands that the Staff's proposed customer growth adjustment should have considered and added to the Company's twelve monthly coincident peak demands during the test year. This data is shown in the first column of Schedule 1-2 of my testimony, attached hereto, for the months of July 2000 through June 2001, which is the test year and the twelve month period used by the Staff for all of the kilowatthour and revenue data in this case. The second column in this schedule indicates the coincident peak demands that should have been deducted from the Company's other regulatory jurisdictions to reflect the loss of both Rolla and Laclede Steel during this twelve month period.

Q. What impact would these coincident demand adjustments have upon the Missouri jurisdictional demand allocation factor proposed by Mr. Bax in this case?

A. The data in Schedule 4 of Mr. Bax's testimony results in a 12 CP Missouri jurisdictional allocation factor of 90.51% for 2001 and 89.49% for 2000. Using this same data from his Schedule 4, for the July 2000-June 2001 test year, results in a 12 CP Missouri jurisdictional allocation factor of 90.09%. Referring to my Schedule 1-2, the additional demands resulting from the Staff's proposed customer growth adjustment have been added to both the Missouri peak loads and the total Ameren peak loads, shown in Schedule 4 of Mr. Bax's testimony, for the July 2000-June 2001 test year in this case. The Rolla and Laclede Steel demands, which are also shown in my Schedule 1-2, have been deducted from the total Ameren peak loads, to reflect their removal from the system.

Q. What were the results of reflecting these updated changes in the calculation of the Missouri 12 CP jurisdictional demand allocation factor for the July 2000 - June 2001 test year?

A. Based upon the data in Schedule 4 of Mr. Bax's testimony, the updated Missouri jurisdictional demand allocation factor resulting from these calculations is 90.92%, based upon the 12 CP allocation methodology recommended by Mr. Bax. This factor is higher than the 90.09% 12 CP factor for the same period. It is also higher than the 90.51% 12 CP factor for 2001 and that of 89.49% for 2000. In fact, it is appropriate to note that correcting these demands in the Staff's analysis, for all of the reasons I stated earlier, will result in a higher Missouri jurisdictional demand allocation factor during any of these recent time periods.

Q. By making these corrections to the Staff's 12 CP calculation for Missouri, are you necessarily endorsing the use of this adjusted 12 CP Missouri jurisdictional demand allocation factor in this case?

A. I do not recommend the use of the Staff's 12 CP Missouri jurisdictional allocation factor, or the adjusted 12 CP factor that I calculated, in this case. I merely developed this adjusted 12 CP Missouri jurisdictional demand allocation factor in order to indicate the direction and the magnitude of the changes in this factor that would result from these necessary corrections to the Staff's analysis. Later in my testimony I will provide evidence that a 4 CP demand allocation methodology is significantly more appropriate to apply to the Company's system costs. This 4 CP Missouri jurisdictional allocation factor, also shown on my Schedule 2-1, is 90.70% based upon Mr. Bax's unadjusted Schedule 4 data. The latter 4 CP allocation factor would increase to 91.54%, based upon the updated demands resulting from the Staff's proposed customer growth adjustment and the lower Rolla and Laclede Steel demands that have been removed from the system. Mr. Weiss is sponsoring the Company's Missouri jurisdictional demand allocation factor in this case.

Q. What are the implications of an increased Missouri jurisdictional demand allocation factor?

A. This allocation factor is used to allocate the Company's system production and transmission plant investment between the Company's Missouri, Illinois and Federal Energy Regulatory Commission (FERC) regulatory jurisdictions. An increase in the Missouri jurisdictional demand allocation factor would result in a greater level of such plant investment, along with associated fixed operating and maintenance expenses, being allocated to the Company's Missouri jurisdiction for purposes of establishing appropriate retail rate and revenue levels in Missouri.

Q. What additional costs would be allocated to the Company's Missouri jurisdiction for each change of one percent (1%) in the Missouri jurisdictional demand allocation factor?

A. This allocation factor is applied to both production and transmission plant, and also to various categories of fixed demand related operating and maintenance expenses associated with these functions. At my request, Company witness Gary S. Weiss performed an analysis to determine the financial sensitivity of a change of one percent (1%) in this allocation factor. This analysis indicated that a change of

$9.1 million in the Company's annual Missouri jurisdictional demand related costs would result from a one percent (1%) change in the Missouri jurisdictional demand allocation factor.

Q. What is the result of applying this $9.1 million differential in allocated annual costs to the difference between the Staff and the Company's Missouri jurisdictional demand allocation factors in this case?

A. The Staff utilized an improperly determined and understated Missouri jurisdictional demand allocation factor of 90.21% (Bax Schedule 5). The Company's proposed Missouri jurisdictional demand allocation factor, sponsored by Mr. Weiss in this case, is 91.36%, a difference of 1.15%. This difference in Missouri jurisdictional demand allocation factors results in $10.5 million ($9.1 x 1.15) of annual cost being excluded from Missouri and assigned to the Company's other jurisdictions, as a result of the Staff's improper determination of this factor.

Q. Please summarize your points regarding Mr. Bax's Missouri jurisdictional demand allocation factor calculations.

A. Mr. Bax and other Staff members adjusted the Company's kilowatthour data to reflect their proposed customer growth adjustments and the loss of the City of Rolla by the Company, as a wholesale customer. Mr. Bax should have also followed through with a set of monthly demand data adjustments to accompany these kilowatthour adjustments, but he did not do so. Mr. Gibbs acknowledged being aware of the Laclede Steel bankruptcy at his deposition in November 2001 (Gibbs Deposition Transcript, page 60, lines 16-25) and, in fairness, he should have asked Mr. Bax to reflect this change in both the calculation of his Missouri jurisdictional demand and energy allocation factors, but he did not do so. While my rebuttal to Mr. Gibbs' testimony summarizes the overall inherent unfairness of the Staff's proposed customer growth adjustment, the Rolla and Laclede Steel changes clearly occurred during the test year and should have been reflected as adjustments in both the Missouri jurisdictional demand and energy allocation factors. My Schedule 1-2 starts with the same data Mr. Bax used and provides the adjustments necessary for Mr. Bax to correct his calculation of the Missouri jurisdictional demand allocation factor. By making these corrections, Mr. Bax will arrive at a higher Missouri jurisdictional demand allocation factor that will more properly assign approximately $10 million of additional annual demand related costs to Missouri, instead of allowing these costs to default to the Company's other jurisdictions.

Staff's Proposed Use of the Twelve Coincident Peak (12 CP) Jurisdictional Demand Allocation Methodology

Q. Turning now to Mr. Bax's selection of the twelve coincident peak demand (12 CP) methodology for developing his jurisdictional demand allocation factor for Missouri, did he make such a recommendation in both the current and earlier versions of his testimony?

A. Yes, he did. In his current testimony, Mr. Bax continues to recommend the use of the 12 CP jurisdictional demand allocation methodology. However, he has somewhat altered the basis for this recommendation between his current March 1, 2002 testimony and his earlier testimony filed on July 2, 2001.

Q. Referring to his earlier testimony filed on July 2, 2001, where did Mr. Bax discuss his recommendation of the 12 CP methodology for determining the Company's Missouri jurisdictional demand allocation factor?

A. In his earlier testimony, he addresses this topic on pages 4-7 of his testimony. On page 4, he indicated he used the twelve coincident peak (12 CP) hour methodology to determine the Missouri jurisdictional allocation factor. He discussed the basis for his 12 CP recommendation on pages 5 and 6 of that testimony, referring to the data contained in his Schedules 2-4.

Q. Referring to his more recent testimony filed on March 1, 2002, where did Mr. Bax discuss his recommendation of the 12 CP methodology for determining the Company's Missouri jurisdictional demand allocation factor?

A. He addresses this topic on pages 4-8 of his current testimony. On page 5, he indicates that the 12 CP hour methodology was used to determine the Missouri jurisdictional demand allocation factor. He explains the basis for his 12 CP recommendation on pages 6 and 7 of his current testimony, referring to the data contained in his Schedule 2.

Q. What is the general reason for using monthly system peaks to determine the allocation of the Company's production plant to its various regulatory jurisdictions?

A. The coincident peak of each month is the single hour of each month during which the electrical usage for the Company's aggregate customer base is the highest. As electric utilities must plan for generation capacity to meet its anticipated maximum peak demands, including adequate reserve levels, it is logical to allocate the cost of such capacity to the various jurisdictions served based upon their proportionate share of the Company's highest peak demands, which normally occur during the summer months of each year.

Q. Is it necessarily rational to base the jurisdictional allocations of an electric utility on the coincident peaks of every month of the year?

A. No, not before a more thorough examination of the statistical relationships of the utility's various monthly seasonal peak demands is performed. For example, where a utility's monthly peak demands during the non-summer period are significantly below its summer monthly peak demands, as is the case for the Company, the lower non-summer demands will have little or no influence on the Company's capacity planning process. With the Company's non-summer peak demands having little or no influence on its capacity planning process, it would not be rational to use such lower monthly demands as a part of the methodology for determining the Company's jurisdictional allocation factors. In addition, it would also be inappropriate to consider all twelve monthly peaks in a jurisdictional allocation methodology when the Company has significant statistical variations in its monthly seasonal peaks. I will supplement these comments regarding the statistical relationships of monthly peak demands later in my testimony.

Q. What is the basis for the 12 CP jurisdictional methodology recommended by Mr. Bax in his earlier July 2, 2001 testimony?

A. He stated at the bottom of page 5 of his previous testimony that "A utility that exhibits only slight variations in its monthly and/or seasonal (e.g. summer and winter) peaks during a particular year would be more likely to utilize the 12 CP method." He then discussed the data in his Schedule 2, which is presented in graphic form in his

Schedule 3, concluding that Schedule 3 "shows relatively high peaks in both the summer and winter." Later on page 6, he commented on the Ratio of Missouri Retail Peak Demand to System Peak Demand table in his Schedule 4, concluding that "these schedules do not indicate a distinct, extraordinary MW peak in any particular monthly CP hour. Therefore, the Staff advocates the use of the 12 CP method."

Q. What is the basis for the 12 CP jurisdictional methodology recommended by Mr. Bax in his more current March 1, 2002 testimony?

A. He states at the bottom of page 6 of his current testimony that "The 12 CP method is appropriate for a utility, such as UE, that experiences marginal variations in monthly and/or seasonal (e.g. summer and winter) peaks during a particular year." He then discusses the data in his Schedule 2, which is presented in graphic form in his Schedule 3, commenting (at the bottom of page 6 and the top of page 7 of his testimony) that "Ameren experiences its highest system peak during the summer months (July, August and September); however, a relatively high system peak also occurs during the winter months (December and/or January)." He also references his Schedule 4, entitled Ratio of Missouri Retail Peak Load to Ameren Peak Load, indicating that "Schedule 4 reflects little variation in the percentage of system peak loads attributed to Missouri retail customers." On page 7 of his testimony he indicates that Schedules 2-4 support the Staff's use of the 12 CP method.

Q. Does the data Mr. Bax referred to in Schedules 2 and 3, of either version of his testimony, meet his criteria of "only slight" or "marginal" variations in monthly and/or seasonal peaks?

A. The information presented by Mr. Bax does not support his criteria, or his selection of the 12 CP jurisdictional allocation methodology, for use in allocating the Company's generation and transmission plant to the various regulatory jurisdictions it serves. It is simply not possible to objectively view the data in either version of Mr. Bax's Schedule 2 and to conclude that the monthly peaks have only a "slight" or "marginal" variation. During his first deposition, Mr. Bax surprisingly defined a "slight variation" to be a variation of up to 40%, (November 28, 2001 Bax Deposition Transcript page 39, lines 13-17), a definition which would be far beyond the expectations of most individuals. During his subsequent deposition, Mr. Bax indicated that his use of these terms was interchangeable and that their meaning was the same (April 24, 2002 Bax Deposition Transcript, page 24, line 22 through page 25, line 3).

Q. Does the data in Mr. Bax's Schedule 2, of either of his testimony versions, contradict his conclusion of a "slight variation" in AmerenUE's monthly peaks, even under his unusual threshold for what constitutes "slight?"

A. Yes, as neither version of Mr. Bax's Schedule 2 supports even his unusual definition of what constitutes a slight or marginal variation. A casual glance at either his earlier or current Schedule 2 indicates that there is much more that a 40% difference between the Company's highest and lowest peaks during these periods.

Q. Is there a clearer and more straightforward way to illustrate the variation in the Company's monthly peaks contained in Mr. Bax's Schedule 2?

A. Yes, there is. I have graphed this same data for both 2001 and the average of the years 1996-2001, respectively, in my Schedules 2-1 and 2-2, attached hereto. These graphs demonstrate more clearly the actual variations in the Company's monthly peaks by comparing the same data used by Mr. Bax in terms of each month's percentage of the minimum month of the year. The comparison in my Schedules 2-1 and 2-2 more clearly illustrate the actual variations between the highest and the lowest monthly peak demands, whereas the schedule presented by Mr. Bax does not show the true variations in the Company's megawatt peaks. The graph on my Schedule 2-1 clearly illustrates that in 2001, the Company's maximum summer peak demand in July exceeded the minimum October demand by 69%. Schedule 2-2 indicates that, on average, the Company's maximum summer peak demand exceeded its minimum non-summer peak demand by approximately 65% during the 1996-2001 period.

Q. Why didn't the graphs in either version of Mr. Bax's Schedule 3 also illustrate these extreme and significant variations in the Company's monthly peaks?

A. While Mr. Bax and I used the same monthly peak demand data to prepare our schedules, the graphs in his Schedule 3 expressed the data as a percentage of the maximum month of the year, which tends to mask the true differences (percentage of high peak above the low peak) and the variations between the Company's seasonal monthly peaks. However, at his deposition Mr. Bax indicated that he changed the vertical scale for the Schedule 3 contained in his March 1, 2002 testimony so that it would provide better support for his testimony and recommendations (April 24, 2002 Bax Deposition Transcript, page 35, lines 12-21).

Q. What data is contained in Schedule 4 of Mr. Bax's testimony and how did he use it to support his 12 CP jurisdictional allocation recommendation in this case?

A. Schedule 4 of his earlier testimony contains monthly Missouri and System peak demand data from 1999-2000, and a calculation of the monthly Missouri peak demand ratio, or percentage, of the total System peak. Comparable data is contained in Schedule 4 of his more current testimony for the years 1999-2001. On Page 6 of his earlier testimony, Mr. Bax commented that "Schedule 4 reflects only slight variations in the percentage of the system peak loads attributed to Missouri retail customers." He relies on the latter statement in recommending that the 12 CP allocation methodology is appropriate for UE. In his more current testimony, however, he states that all of the data on Schedules 2-4 of that testimony support the use of the 12 CP jurisdictional demand allocation methodology (March 2002 Bax Direct Testimony, page 7, lines 15-16).

Q. What is wrong with Mr. Bax's conclusion that the data he refers to (in Schedule 4 of either version of his testimony) supports use of a 12 CP jurisdictional demand allocation factor?

A. There are several things wrong with this conclusion. In the earlier version of his testimony, filed on July 2, 2001, Mr. Bax relied almost exclusively on the data in his earlier Schedule 4 as his support for his recommendation of the 12 CP jurisdictional demand allocation methodology. Now, in the latest version of his testimony, he simply states that all of the data in Schedule 2-4 support his conclusions (March 2002 Bax Direct Testimony, page 7, lines 15-16). Addressing Schedule 4 (in either testimony version), the ratios contained in that schedule are not monthly peaks, but mere percentage components, or ratios, of the Missouri monthly peaks to the Company's total monthly peaks. As such this Schedule 4 data is really a series of monthly Missouri jurisdictional allocation factors. By relying on such data for his recommendation Mr. Bax is, in effect, arbitrarily using the twelve individual monthly ratios, i.e., Missouri jurisdictional allocation factors, to support the use of the 12 CP jurisdictional demand allocation methodology for the Company, which is simply circular reasoning. Moreover, Mr. Bax cited no references or authority that supports the arbitrary approach he used in either versions of his direct testimony or depositions.

Q. In the earlier version of his testimony in this area, Mr. Bax inferred that the apparent slight variations in the Schedule 4 ratio data provided added support for the use of the 12 CP jurisdictional demand allocation methodology. Do you agree that the Schedule 4 data supports the use of the 12 CP jurisdictional demand allocation methodology?

A. I do not agree that his Schedule 4 data supports the use of the 12 CP jurisdictional demand allocation methodology. These individual monthly ratios are totally irrelevant to the decision of which methodology to use in arriving at the appropriate jurisdictional allocation factor for any of the Company's regulatory jurisdictions. The slight variations in these monthly ratios that Mr. Bax references are not variations in the Company's monthly peak demands at all, but rather are simply variations in the monthly demand ratios, i.e., the percentage of the Company's total monthly System peak demand that is located in Missouri. That these monthly variations are small indicates nothing more than the obvious fact that the Company's total System demands are highly correlated with total Missouri demand (which should be expected as AmerenUE's Missouri retail operations represent approximately 90% of total AmerenUE). In short, the information in Mr. Bax's Schedule 4 provides absolutely no support for his decision to use a 12 CP jurisdictional demand allocation methodology.

Q. What is this slight variation that Mr. Bax refers to in his Schedule 4 data?

A. The maximum variation that occurs in 2001 is between the ratios for the months of March and July, a difference of 0.0327 (0.9169 - 0.8842), which is 3.27%. However, in Schedule 5 of his original testimony filed on July 2, 2001, the difference in the Missouri 12 CP and 4 CP allocation factor ratios is only 0.0096 (0.9057 - 0.89.61), which is 0.96%. If his Schedule 4 variation of 3.27% is considered to be "only slight," Mr. Bax should then be indifferent to using the 4 CP jurisdictional demand allocation factor that I will subsequently recommend in my testimony as being more appropriate based upon the actual pattern of the Company's monthly peak demands.

Q. What is your overall opinion regarding the support for the 12 CP jurisdictional demand allocation methodology that is contained in either version of the testimony of Mr. Bax?

A. There is no support for the use of the 12 CP jurisdictional demand allocation methodology, based upon the testimony Mr. Bax has submitted in this case. Mr. Bax has overlooked significant seasonal variations in the Company's monthly peak demands. In the case of his Schedule 4 data, he simply misinterpreted what that data actually represented and relied upon an improper interpretation of variations in the monthly jurisdictional ratios contained in that schedule to recommend a jurisdictional demand allocation methodology that is not appropriate for the Company.

Q. Is there a more definitive and objective way to evaluate the appropriate jurisdictional demand allocation methodology for a given utility system?

A. Yes, there are various monthly peak statistical tests, relied upon and employed in orders issued in a number of electric utility cases at the FERC, that can be used to make this determination. The Company performed six analyses based upon these FERC tests, using the Ameren monthly peaks for the years 1996-2001, which appear in Schedule 2 of the most recent testimony filed by Mr. Bax. The Company performed three separate analyses for both a) the most recent calendar year (2001) and b) the average monthly peaks for the entire 1996-2001 time period. The second analysis, covering six years of Ameren monthly peaks, was performed in order to smooth out any abnormalities that might have occurred in any individual monthly peaks during this period as a result of extreme weather conditions or other unusual or abnormal events. All of the data used by the Company in conducting these tests were obtained from Schedule 2 of Mr. Bax's testimony. The Company's calculations are contained in Schedule 3-1 of my testimony, attached hereto. This same data was also displayed earlier using a graphic format (indexed to minimum peak) in Schedules 2-1 and 2-2 of my testimony.

Q. Using the results of these analyses, which jurisdictional demand allocation methodology would be the most appropriate for the Company, based upon its actual historic pattern of monthly system peak demands?

A. All of the tests employed in these analyses indicate, conclusively, that the Company is not a 12 CP jurisdictional demand allocation methodology utility. Instead it is a 4 CP (or perhaps even a 3 CP) utility, under the standards established and applied by the FERC.

Q. Which FERC jurisdictional demand allocation methodology tests did the Company examine?

A. The Company examined the following three general statistical tests developed and used by the FERC for this determination: 1) the on and off-peak relative demand test, 2) the low to annual peak demand test and 3) the average to annual peak demand test.

Q. Please describe the first of these three FERC jurisdictional demand allocation methodology tests, the on and off-peak test.

A. The on and off-peak test compares the Company's average on-peak period demands, as a percentage of the Company's annual peak demand, with the Company's average off-peak period demands, as a percentage of the Company's annual peak demand. Large differences between these two figures tend to support something other than the 12 CP jurisdictional demand allocation methodology, while smaller differences tend to support 12 CP. This comparison of on and off-peak demands relative to the Company's peak demand yielded a difference of 24.73% for the year 2001 and 25.60% for the years 1996-01. The FERC decisions adopt a 4 CP jurisdictional demand allocation methodology under this test whenever this difference was in the range of from 26 to 31%. The Company's data for both of the data sets examined are just slightly below this lower FERC limit for classification as a 4 CP utility. However, the FERC cases that adopted a 12 CP jurisdictional demand allocation methodology, under this test, did so when the difference between the on and off-peak demand percentages ranged from 18 to 19%, which is substantially less than the range of the data resulting from the Company's calculations.

Q. Please describe the second of the three FERC jurisdictional demand allocation methodology tests, the low to annual peak test.

A. The low to annual peak demand test calculates the Company's lowest monthly system peak demand as a percentage of its annual peak demand. The higher the percentage, the greater the support for the 12 CP jurisdictional demand allocation methodology. The Company's percentage of monthly low to peak demands was 59.24% in the year 2001 and 60.48% for the years 1996-01. These percentages fit well within the percentage range for the FERC cases that adopted a 4 CP jurisdictional demand allocation methodology, which was from 56 to 62%. The percentage range for the FERC cases that adopted a 12 CP jurisdictional demand allocation methodology was from 66 to 80%, which is substantially above the percentages calculated using the Company's data.

Q. Please describe the third FERC jurisdictional demand allocation methodology test, the average to annual peak test.

A. The average to annual peak demand test calculates the Company's average monthly system peak demands as a percentage of its annual peak demand. The higher the percentage, the greater the support for the 12 CP jurisdictional demand allocation methodology. The Company's average monthly system peak demand as a percentage of its annual peak demand was 78.36% in the year 2001 and 77.71% for the years 1996-01. The FERC decisions adopting a 4 CP jurisdictional demand allocation methodology under this test based that conclusion on differences ranging from 79 to 81%. The Company's data for both of the data sets examined are just slightly below (on the low side) of this FERC range for classification as a 4 CP utility, indicating that the Company may even be less than a 4 CP methodology utility. In contrast, the FERC cases that adopted a 12 CP jurisdictional demand allocation methodology, under this test, did so when the average monthly peaks to annual peak demand percentages ranged from 81 to

88%, which is substantially higher than the percentages resulting from the Company's data.

Q. What source did you rely upon for this information regarding the FERC jurisdictional demand allocation factor tests?

A. I relied upon the publication entitled "A Guide to FERC Regulation and Ratemaking of Electric Utilities and Other Power Suppliers." The third edition of this guide was published in 1994. Its author was Michael E. Small, an attorney and former FERC Special Assistant to the Deputy General Counsel for Litigation and Enforcement. A copy of the relevant portion of this publication is attached hereto as Schedule 3-2 of my testimony. These FERC case results, referenced above, are currently being used by the FERC in both wholesale power and transmission rate cases.

Q. What would be the detrimental consequences of the Company continuing to have its Missouri jurisdictional costs based upon a 12 CP allocation methodology?

A. As explained above, under the FERC's established and applied standards, AmerenUE is a 4 CP jurisdictional allocation methodology utility. The Company's other retail jurisdiction, the State of Illinois, also employs the 4 CP jurisdictional allocation methodology in the Company's cases. If the Missouri Commission were to continue to employ a methodology other than 4 CP, the sum of the Company's jurisdictional demand allocation factors will continue to add up to less than 100%, which would continue to deprive the Company of the opportunity to recover 100% of the total costs it is incurring in providing utility service.

Staff's Proposed Missouri Jurisdictional Energy Allocation Factor

Q. Turning now to the methodology employed by Mr. Bax in developing his jurisdictional energy allocation factor for Missouri, where is this calculation illustrated in his testimony?

A. As indicated earlier, Mr. Bax calculates his recommended Missouri jurisdictional energy allocation factor in Schedule 6 of his March 1, 2002 testimony. He did not sponsor this calculation in his prior testimony. As I also indicated earlier in my testimony, Mr. Bax reflected some of the Staff kilowatthour adjustments in this Schedule 6, but made no accompanying adjustments of any kind in performing the Missouri jurisdictional demand calculation shown in his Schedule 5.

Q. Are the kilowatthour adjustments made by Mr. Bax in his Schedule 6 all of the adjustments that he should have made?

A. Mr. Bax did not make adjustments in his Schedule 6 that reflect all of the kilowatthour adjustments being proposed by the Staff in this case (April 24, 2002 Bax Deposition Transcript, page 18, line 16 through page 20, line 5). His Schedule 6 reflects the Staff's weather normalization adjustment and the loss of the City of Rolla. I have previously mentioned that an adjustment is required to reflect the bankruptcy of Laclede Steel Company in Illinois. In addition to these adjustments, the Staff is also proposing kilowatthour adjustments for 1) miscellaneous billing and rate switching changes, 2) a 365 day normalization and 3) customer growth. Each of these adjustments affects Missouri kilowatthour sales during the test year and should have also been considered by Mr. Bax in his Schedule 6 calculations.

Q. Even if Mr. Bax were to correct his Schedule 6 to reflect the kilowatthours of all of these adjustments, is it appropriate to calculate a jurisdictional energy allocation factor based upon metered kilowatthour sales, which is the basis of the data in Schedule 6?

A. The use of kilowatthour sales is not appropriate for the determination of this allocation factor, as these sales represent kilowatthours at customer meters, which are installed at various voltage levels within the Company's distribution system. Due to different levels of losses associated with the different voltages across the system, these kilowatthours at the customers' meters are not equivalent to what needs to be generated to supply the kilowatthours at the metered voltage level.

Q. What is the appropriate manner in which to calculate a jurisdictional energy allocation factor?

A. All metered kilowatthour sales must be appropriately adjusted for losses back to a common point of equivalency on the system, which is usually the high side of the Company's transmission system or at the system generation level. Developing an allocation factor at these levels will ensure that all customer classes are being allocated the appropriate level of system energy losses associated with the voltage at which they receive their service. These differences in losses associated with the Company's different customer classes were discussed earlier in my testimony.

Q. Do the Company's losses also vary among its various jurisdictions?

A. Yes, nearly all of the wholesale customer service is supplied at 34,500 volts, the same as the service to some of the Company's larger industrial customers. The Company's Illinois jurisdiction is heavily dominated by large industrial loads served at high voltage levels, which means that the losses associated with that jurisdiction are also lower than losses in the Missouri retail jurisdiction.

Q. Does it follow then that each of the Company's jurisdictions must be properly adjusted for losses to reflect this varying mix of customer voltages, prior to the determination of any jurisdictional energy allocation factor?

A. Yes, because of the reasons I mentioned above, it would be unfair to the Company's wholesale and Illinois customers to be allocated, or to be assumed to have, the same level of system losses as the Missouri jurisdiction. It is also unfair to the Company to have its Missouri costs improperly shifted to other jurisdictions where it has little or no opportunity to recover such costs.

Q. Have you estimated the appropriate level of the Company's system energy losses that should have been considered by Mr. Bax in his development of the jurisdictional energy allocator, considering all of the Staff's kilowatthour adjustments, as well as the loss of Rolla and Laclede Steel?

A. Yes, I have. Based upon the Company's voltage related loss factor data and jurisdictional mix of customers, I began with the same total kilowatthour sales data on Mr. Bax's Schedule 6 and then estimated the distribution of total Company losses among its Missouri, Illinois and wholesale jurisdictions. In order to incorporate all of the Staff's proposed kilowatthour adjustments into the jurisdictional energy allocation factor calculation, I then added an appropriate loss factor to each of the Staff's proposed kilowatthour sales adjustments, including adjustments for Rolla and Laclede Steel, and applied each adjustment's total (including losses) to the Output for Load of each jurisdiction. The resulting adjusted Output for Load, which reflects all of these adjustments, is the basis for the development of the jurisdictional energy allocation factor. I developed this data for the months of July 2000 through June 2001, which is the twelve month period used by the Staff for all of the kilowatthour and revenue data in this case. The results of these calculations are shown on the attached Schedule 3-3 of my testimony.

Q. What were the results of these calculations in your Schedule 3-3, and how should this data be used to correct Mr. Bax's calculation of the Missouri jurisdictional energy allocation factor?

A. Mr. Bax calculates this factor on Schedule 6 of his testimony as 87.54%. The correction made to his calculation in my Schedule 3-3 would increase the Missouri jurisdictional energy allocation factor to 89.96%. By failing to make these corrections, Mr. Bax is improperly allocating Missouri jurisdictional energy costs to the Company's Illinois and wholesale jurisdictions. If he makes these corrections, Mr. Bax will arrive at a higher Missouri jurisdictional energy allocation factor that will more properly assign approximately $17 million of additional annual energy costs to Missouri, instead of allowing these costs to default to the Company's other jurisdictions.

Q. By making these corrections to the Staff's calculation of the Missouri jurisdictional energy allocation factor, are you endorsing the use of the adjusted Missouri jurisdictional energy allocation factor shown on the last line of your Schedule 3-3 in this case?

A. I do not recommend the use of this adjusted Missouri jurisdictional energy allocation factor in this case, as the Company does not accept either the concept, or the order of magnitude, of several of the Staff's kilowatthour adjustments. I merely developed the adjusted Missouri jurisdictional energy allocation factor in order to indicate the direction and the magnitude of the changes in this factor that would result from the corrections that Mr. Bax failed to make in his analysis. Mr. Weiss is sponsoring the Company's Missouri jurisdictional energy allocation factor in this case.

Q. What additional costs would be allocated to the Company's Missouri jurisdiction for each change of one percent (1%) in the Missouri jurisdictional energy allocation factor?

A. This allocation factor is applied to variable fuel and purchased power expenses, and also to various categories of energy related operating and maintenance expenses associated with production plant. At my request, Company witness Gary S. Weiss performed an analysis to determine the financial sensitivity of a change of one percent (1%) in this allocation factor. This analysis indicated that a change of $7.1 million in the Company's annual Missouri jurisdictional energy related costs would result from a one percent (1%) change in the Missouri jurisdictional energy allocation factor.

Q. What is the result of applying this $7.1 million differential in allocated annual costs to the difference between the Staff and the Company's Missouri jurisdictional energy allocation factors in this case?

A. The Staff utilized an improperly determined and understated Missouri jurisdictional energy allocation factor of 87.54% (Bax Schedule 6). The Company's Missouri jurisdictional energy allocation factor, sponsored by Mr. Weiss in this case, is 88.45%, a difference of 0.91%. This difference in Missouri jurisdictional energy allocation factors results in $6.5 million ($7.1 x 0.91) of annual cost being excluded from

Missouri and assigned to the Company's other jurisdictions, as a result of the Staff's improper determination of this factor.

Q. Please summarize your points regarding Mr. Bax's Missouri jurisdictional energy allocation factor calculations.

A. On his Schedule 6 Mr. Bax adjusted the Company's jurisdictional kilowatthour data to reflect the Staff's proposed weather adjustment and the loss of the City of Rolla by the Company, as a wholesale customer. Mr. Bax should have also followed through with a set of kilowatthour adjustments to accompany all other Staff adjustments for rate switching and miscellaneous (sponsored by Staff witness Janice Pyatte), 365 day adjustment (sponsored by Staff witness Lena Mantle) and customer growth (sponsored by Staff witness Doyle Gibbs). However, Mr. Bax did not make such adjustments. Mr. Gibbs had information regarding the Laclede Steel bankruptcy from his review of the company's uncollectible expense, and in fairness he should have asked Mr. Bax to reflect this change in both the calculation of his Missouri jurisdictional demand and energy allocation factors, but he did not do so. While my rebuttal to Mr. Gibbs' testimony summarizes the overall inherent unfairness of the Staff's proposed customer growth adjustment, the Rolla and Laclede Steel changes clearly occurred during the test year and should have been reflected as adjustments in both the Missouri jurisdictional demand and energy allocation factors. My Schedule 3-3 starts with the same data Mr. Bax used in his Schedule 6 and provides the adjustments necessary for Mr. Bax to correct his calculation of the Missouri jurisdictional energy allocation factor. By making these corrections, Mr. Bax will arrive at a higher Missouri jurisdictional energy allocation factor that will more properly assign approximately $17 million of *additional annual energy related costs to Missouri, instead of allowing these costs to* default to the Company's other jurisdictions.

Summary of Staff's Loss and Allocation Factor Proposals

Q. Please summarize your rebuttal testimony regarding the various areas covered by the testimony being sponsored by Mr. Bax.

A. The areas covered by Mr. Bax's testimony were 1) system energy losses; 2) selection of the demand allocation methodology applicable to the Company; 3) calculation of the Missouri jurisdictional demand allocation factor; and 4) calculation of the Missouri jurisdictional energy allocation factor. My positions on each of these areas of Mr. Bax's testimony are summarized below.

Q. What is your position regarding Mr. Bax's system energy loss factor calculation, and the Staff's subsequent use of this factor?

A. Mr. Bax calculated an annual average system loss factor in his testimony. While his mathematics were performed correctly for the data Mr. Bax used and the calculation he made, this average loss factor is not appropriate for the manner in which it was used by the Staff to add losses to the various kilowatthour adjustments they are proposing in this case. In particular, the use of this average loss factor significantly understates the losses associated with the Staff's proposed customer growth adjustment in three ways: 1) it fails to account for the higher losses that are incurred in the peak summer months of July-September, 2000, which were the months containing the larger portion of the Staff's proposed customer growth adjustment; 2) it fails to account for the higher losses that are incurred during the higher peak hours, considering the customer load profiles in the months in which the Staff's proposed customer growth adjustment was made, which are the hours during which the majority of the usage from additional customers will take place; and 3) it fails to account for the higher losses that are incurred by the Company in serving low voltage customers, which constitute the majority of the Staff's proposed customer growth adjustment. As explained in detail in my testimony, the Staff's use of this average annual system loss factor for all periods of the year and for all customer classes, while ignoring the above factors, results in their allowance being too low for the additional production expenses associated with their proposed customer growth adjustment.

Q. What is your position regarding the 12 CP jurisdictional demand allocation methodology recommended by Mr. Bax to be applied to the Company's production and transmission plant?

A. This recommendation by Mr. Bax is based upon faulty analysis, and it is without any support or examination of the relevant facts that should have been considered in making an objective determination of the jurisdictional demand allocation methodology actually applicable to the Company. The significantly more objective statistical analysis and application of the FERC tests, illustrated in Schedule 3 of my testimony, shows conclusively that the Company is <u>not</u> a 12 CP demand allocation methodology company and that the Company is either a 4 CP or a 3 CP jurisdictional demand allocation methodology company.

Q. What is your position regarding Mr. Bax's calculation of the Missouri jurisdictional demand allocation factor?

A. Mr. Bax used only the Company's actual monthly peak demands in making this calculation. By doing so, he failed to increase the Company's monthly coincident peak demands to reflect the Staff's proposed customer growth adjustment. He also failed to reflect the Company's loss of the City of Rolla and Laclede Steel Company, respectively, from the wholesale and Illinois jurisdictional demands. Had these adjustments been considered by Mr. Bax in his calculation of the Missouri jurisdictional demand allocation factor, the factor would have increased, resulting in additional production and transmission plant being appropriately allocated to Missouri. This increase in the Missouri jurisdictional demand allocation factor, that would result from these demand adjustments, would occur under either the unsupported 12 CP allocation methodology recommended by Mr. Bax, or the 4 CP allocation methodology that I am recommending.

Q. *What is your position regarding Mr. Bax's calculation of the Missouri jurisdictional energy allocation factor?*

A. Mr. Bax developed his Missouri jurisdictional energy allocation factor based upon the Company's kilowatthour sales at its customers' meters, which is incorrect because all of the kilowatthours are not being accounted for at a common voltage level on the Company's system. As a result, these non-equivalent kilowatthours are unsuitable for use in calculating an energy allocation factor. Moreover, even if Mr. Bax had properly adjusted these kilowatthours for losses, his methodology would still be deficient because he did not consider the other kilowatthour adjustments proposed by the Staff, including the loss of Rolla and Laclede Steel. If the system losses associated with all of these proposed Staff adjustments are properly considered, the Missouri jurisdictional energy allocation factor would increase to the level indicated in my Schedule 3-3. Had Mr. Bax properly considered the Company's jurisdictional kilowatthours adjusted for losses to a common point on the Company's transmission or generation system, and accounted for all of the other kilowatthour adjustments being proposed by the Staff in this case, as well as the losses of Rolla and Laclede Steel, the Missouri jurisdictional energy allocation factor would have increased, resulting in additional variable fuel and other production costs being appropriately allocated to Missouri. His failure to correct all of his analyses for the items I have mentioned results in an inappropriate allocation of Missouri jurisdictional energy costs to the Company's Illinois and wholesale jurisdictions.

REBUTTAL OF TESTIMONY OF JAMES C. WATKINS

Staff's Proposed Class Revenue Adjustments and Rate Design

Q. Turning now to the rate design testimony of Mr. Watkins. What rate design recommendations did Mr. Watkins make?

A. Mr. Watkins makes two recommendations at the top of page 3 of his testimony. First, Mr. Watkins recommends a method for distributing any rate reduction ordered by the Commission in this case to the Company's retail rate classes. Second, he recommends specific rate differentials to be employed in the design of the Company's similarly structured Large General Service (LGS) and Small Primary Service (SPS) Rates as a part of this case.

Q. Do you agree with these Staff recommendations made by Mr. Watkins?

A. I do not believe that relying upon the Stipulation and Agreement from the Company's last rate design case, Case No. EO-96-15, is an appropriate basis for the distribution of the total revenue requirement, or any revenue adjustments resulting from this case. Therefore, I disagree with the first recommendation made by Mr. Watkins. However, in developing its proposed rates for the test year in this case, the Company will consider his second recommendation, regarding the proposed rate differentials between the LGS and SPS Rates as a rate design objective.

Q. Why do you disagree with the use of the stipulation from the Company's last rate design case to establish adjustments to the class revenues in this case?

A. There are several reasons why the use of this stipulation is inappropriate for this purpose. First, this recommendation from the prior case was a part of a Stipulation and Agreement, and that stipulation contained language which makes its terms non-binding in the future on all parties that signed it. Second, the test period used in that earlier case was the twelve month period from October 1995 to September 1996, and several significant changes in operations and cost levels have taken place at Ameren since that time. One major change was the completion of Union Electric's merger with Central Illinois Public Service Company and the synergies that resulted therefrom. Other changes include the implementation of new automated meter reading system and a new customer billing system, the introduction of new voluntary curtailment tariffs, the elimination of interruptible tariffs, various customer rate switching and general overall system growth.

Q. Even ignoring all of these changes at the Company, is the test year in that earlier case (Case No. EO-96-15) simply too old to use in establishing class revenue adjustments that will be implemented in the year 2002?

A. Yes, the data from the test year utilized in EO-96-15 is simply too outdated to be used in this proceeding. In fact, in its Order Establishing Test Year and Procedural Schedule in this case the Commission stated that a "test year from July 1, 1999, to June 30, 2000, would result in rates based on outdated cost information and a significant but unnecessary increase in the number of issues to subsequently be adjusted and decided by the Commission." This statement by the Commission would apply even more so to the considerably older 1995-96 costs and operational levels reflected in the Company's previous rate design case.

Q. You have provided several reasons why the proposal made by Mr. Watkins is not an appropriate basis for the distribution of any Company revenue reductions resulting from this case. What is the Company's proposal in this regard?

A. Due to the age of the data in the stipulated rate design case, as well as the other corporate, operational, rate and customer changes that have occurred since that time, I recommend that the Company's total revenues, and any increases or decreases in these revenues which might result from this case, be distributed to the Company's customer classes using an updated class cost of service study based upon the July 2000-June 2001 test year recently established by the Commission for this case. Company witness William M. Warwick conducted an updated class cost of service study for this case, under my supervision, and he is sponsoring that study in testimony filed in this proceeding.

Class Cost of Service Concepts and Operating System Components

Q. Please explain what is meant by "class cost of service."

A. The Company currently provides service to its customers in a number of rate classifications that are designated for residential or non-residential service. The non-residential customer group is differentiated by customer size and the voltage level at which the Company provides their service. The current customer classes are Residential, Small and Large General Service (all of which have their service delivered at a low secondary voltage level), Small and Large Primary Service (delivery at a high voltage level) and lighting service (both area and street lighting). A class cost of service study provides a basis for allocating and/or assigning the Company's total jurisdictional cost of providing electric service to these various customer classes in a manner which best reflects cost causation. The results of a class cost of service study are often referred to as "class revenue requirements," which represent the responsibility of each customer class for its equitable share of the Company's total annual cost of providing electric service within a given jurisdiction (Missouri in this case).

Q. How are the results of a class cost of service study used by the Company?

A. These study results, or class revenue requirements, are used to establish the level of annual revenue which the Company should recover from each customer class, through the application of the rates or charges within the Company tariffs under which the various customer classes are being served.

Q. Please define your use and application of the term "rate design."

A. The term "rate design" refers both to the process of establishing the specific charges (e.g. monthly customer charges, dollars per kilowatt demand and/or cents per kilowatthour energy charges) for each customer class, as well as to the actual structure of an individual class rate. The rate design or structure of a given class rate may range in complexity from a simple structure consisting of a monthly customer charge and a flat charge per kilowatthour (such as the Company's summer Residential Rate), to a more complex set of customer, demand, energy and reactive charges (such as the Company's Small and Large Primary Service Rates). In all instances, however, the charges within a specific rate classification are established such that the application of these individual charges to the total annual customer class electrical usage will result in the collection of the annual revenue requirement, or cost of service, of each of the Company's retail rate classes.

Q. As background for additional discussion on the class cost of service study the Company is recommending in this case, please provide a general description of the various facilities utilized by the Company in producing and delivering electricity to its customers.

A. Schedule 4 of my testimony is a simplified diagram illustrative of the Union Electric system, showing how power flows from the generating station and is then transmitted and distributed to the home of a residential customer. Other customers receiving service at higher voltage levels are also served from various points on the same system.

Q. Please describe, in more detail, how the Company's system operates.

A. As illustrated on Schedule 4, electrical power is produced at the Company's generating stations at voltage levels ranging from 11,000 to 23,750 volts. To achieve transmission operating economies, this voltage is raised, or stepped up, by power transformers at the generating station sites to voltages generally ranging from 138,000 to 345,000 volts for transmission to the Company's bulk substations that are strategically located throughout its service area.

Q. What is the function of the Company's bulk substations?

A. Bulk substations receive electrical power at transmission voltage levels. They then lower, or step-down, this power to other transmission or distribution voltages generally ranging from 138,000 volts to 34,500 or 69,000 volts. Such power is then distributed over the Company's 34,500 or 69,000 volt distribution lines to distribution substations located throughout the Company's service area.

Q. What function do distribution substations perform?

A. Distribution substations, which are far more numerous than bulk substations, provide a further reduction in the electrical power voltage to a range of 4,160 to 13,800 volts within various portions of the Company's service area. Such power is then distributed over the Company's 4,160 to 13,800 volt distribution lines to points at or near the premises of the Company's customers.

Q. After electrical power at 4,160 to 13,800 volts is delivered to a point at or near a customer's premises, do any further reductions in voltage take place?

A. Yes, in most instances. While approximately 650 of the Company's largest industrial and commercial customers take service at the 4,160 to 13,800 volt range or higher in Missouri, the majority of the Company's customers are served at lower voltages, ranging from 120 to 480 volts. Such lower voltages are achieved through the use of numerous line transformers located at or near such customer's premises. This low voltage electrical power from the line transformer is delivered to a customer's premises over low voltage lines referred to as "secondary" and "service" lines.

Q. What voltages are utilized in providing electric service to residential customers?

A. Residential customers are served at either 120 or 240 volts depending upon the customer's service entrance panel size and connected appliances.

Q. What voltages are utilized to serve non-residential customers?

A. Non-residential customers on the Company's Small and Large General Service Rates are served at voltages from 120 to 480 volts due to the wide variety of electrical consuming devices utilized by such customers. Customers in the latter voltage range are often referred to as "secondary" voltage customers. Other larger non-residential customers receiving service at 4,160 to 13,800 volts are referred to as "primary" voltage customers. The Company also serves approximately 50 customers in Missouri at voltages above the 13,800 volt level. These are referred to as "high voltage" or Rider B customers.

Q. In your description of the Union Electric generation, transmission and distribution system are you using the term "lines" in a general sense?

A. Yes, as such lines may be overhead conductors or underground cables. Overhead lines include all poles, towers, insulators, crossarms and all other hardware associated with such installations. Underground "lines" include direct buried cable as well as that installed in single or multi-duct conduit, and other associated hardware.

Q. Please describe the components of costs and revenues that are contained in the class cost of service study the Company is recommending in this case.

A. A traditional cost of service study incorporates the aggregate jurisdictional (Missouri, Illinois or FERC) accounting and financial data normally submitted to a regulatory commission by a utility in support of a request for an adjustment in its overall rate levels. Such a study is required to determine the level of revenues necessary for the Company to recover its operating and maintenance expenses, depreciation provisions applicable to its investment in utility plant, property taxes, income and other taxes, and a fair rate of return to the Company's investors, through its rates. The Company's class cost of service study allocates, or distributes, these total jurisdictional costs to the various customer classes in a manner that fairly and equitably reflects the cost of the service being provided to each customer class.

Q. Was a Missouri jurisdictional study performed by the Company's Regulatory Accounting group the starting point for the class cost of service study performed and sponsored by Mr. Warwick?

A. Yes, it was. As I indicated above, the Company's class cost of service study is a continuation and refinement of a Missouri jurisdictional cost of service study, resulting in a determination of the costs incurred in providing electric service to each of the Company's customer classes.

Q. What categories of cost were examined in the development of the allocated class cost of service studies being sponsored by Mr. Warwick in this case?

A. A detailed analysis was made of all elements of the Company's Missouri jurisdictional rate base investment and expenses during the test year, for the purpose of allocating such items to the Company's present customer classes. This analysis consisted of classifying the various elements of cost into their customer-related, energy-related and demand-related cost categories.

Q. Why are the Company's costs classified into these three categories?

A. It is generally accepted within the industry that each of these categories of cost are incurred by the Company as a result of different cost causation factors and, hence, should be allocated among the various customer classes by different methodologies which consider such cost causation.

Q. What are customer-related costs?

A. Customer-related costs are the minimum costs necessary to just make electric service available to the customer, regardless of the extent to which such service is utilized. Examples of such costs include monthly meter reading, billing, postage, customer accounting and customer service expenses as well as a portion of the costs associated with the required investment in a meter, the service line, transformer and other distribution facilities. The customer components of the distribution system are those costs necessary to simply make service available to a customer, without the consideration of the amount of the customer's electrical use. The January 1992 edition of the Electric

Utility Cost Allocation Manual, published by the National Association of Regulatory Utility Commissioners (NARUC) references both customer-related and demand-related cost components for all distribution plant and operating expense accounts other than for substations and street lighting.

Q. What are energy-related costs?

A. Energy-related costs are those costs related directly to the customer's consumption of electrical energy (kilowatthours) and consist primarily of fuel, fuel handling, a portion of production plant maintenance expenses and the energy portion of net interchange power costs.

Q. What are demand-related costs, which are the third category of costs you referred to?

A. Demand-related costs are rate base investment and related operating expenses associated with the facilities necessary to supply a customer's service requirements during periods of maximum, or peak, levels of power consumption each month. During such peak periods this usage is expressed in terms of the customer's maximum power consumption, commonly referred to as kilowatts of demand. As so defined, demand-related costs include those costs in excess of the aforementioned customer and energy-related costs. The major portion of demand-related costs consists of generation and transmission plant and the non-customer-related portion of distribution plant.

Q. After the Company's costs are categorized into one of these three classifications, how are they allocated to the various rate classes?

A. Customer-related costs are normally allocated on the basis of the number of customers associated with each rate class. In some instances involving non-residential customer multiple metering installations, weighting factors may also be used. In addition, where specific costs can be identified as being attributable to one or more specific customer classes, such as credit and collection expenses, a direct assignment of such costs will be made.

Energy-related costs are allocated to the customer classes on the basis of their respective energy (kilowatthour) requirements at the generation level of the Company's system, which includes applicable system energy losses. The use of this common point on the Company's system to allocate such costs insures that each customer class will be assigned the appropriate portion of the Company's total incurred variable fuel and purchased power costs.

Demand-related distribution costs are allocated to customer classes using one or more allocation factors based upon customer class coincident, class non-coincident or individual customer non-coincident kilowatt demands. Demand-related transmission costs were allocated to customer classes on a 12 CP basis as that was the methodology that applied to the combined demands of Ameren and all of the other utilities participating in the Alliance Regional Transmission Operator (ARTO) filing at the FERC. Demand-related production costs are allocated on the basis of the Average & Excess (A&E) Demand Method referenced in the NARUC cost allocation manual that I referred to earlier. As not all customers have demand meters, customer class and individual kilowatt demand data is obtained from the Company's ongoing load research program.

Q. As generation (production) plant consists of more than half of the Company's total plant investment, please summarize the most common cost allocation methodologies employed within the electric utility industry for the allocation of generation plant.

A. The most common and generally accepted methodologies used for the allocation of generation plant can be grouped into the following three categories:

<u>Peak Responsibility</u> – Costs are allocated on the basis of the relative customer class demands at the time of occurrence of the Company's system peak during the period of study (referred to as the "coincident peak" or "CP" method). One or more system peak hours, or a number of monthly or seasonal system peaks, are normally used in applying the CP methodology.

<u>Non-Coincident Peak</u> – Allocates costs on the basis of the maximum peak demand of each customer class at any time during the study period, without regard to the time of occurrence or magnitude of the Company's coincident system peaks (referred to as the "NCP" method). As with the CP method, the NCP methodology can employ one or more customer class peaks in its application.

<u>Average and Excess Demand</u> (referred to as the A&E method). – Allocates costs by determining cost allocation factors based upon a weighting of average class demand throughout the year (kilowatthours ÷8760 hours) and class "excess" demand(s). The excess demand(s) used in this determination are the class NCP demand(s) in excess of the average class demand during the study period. As with the CP and NCP methodologies, this method can also employ the use of one

or more customer class NCP demands to determine class excess demands. Average class demands are weighted by the Company's annual system load factor (LF = average demand ÷ peak demand) and excess class demands are weighted by the complement of load factor (1.0 – LF) in the development of cost allocation factors using this methodology.

Q. Which cost allocation methodology is the Company using for production plant in its class cost of service study in this case?

A. The Company is utilizing the 4 NCP version of the Average and Excess Demand methodology for allocating production plant in this case.

Q. What were the considerations associated with the Company's election to utilize the A&E allocation methodology for production plant in this case?

A. Two of the major factors associated with generation capacity planning prompted the use of the A&E cost allocation methodology. Generally, system peak demands and, to a major extent, excess customer demands, are the motivating factors which influence the <u>amount of capacity</u> the Company must add to its generation system to provide for its customers' maximum demands. However, the <u>type of capacity</u> (base, intermediate or peaking) which the Company must add is not dictated by maximum customer demand alone, but also by the annual energy, or kilowatthours, which will be required to be generated by such capacity, i.e., the generation unit's utilization factor. A cost allocation methodology that gives weight to both a) class peak demands and b) class energy consumption (average demands) is required to properly address both of the above considerations associated with capacity planning. The A&E methodology gives weight to both of these considerations by its inclusion of both average class demands, which are kilowatthours divided by total annual hours (8,760), and the excess NCP demands of each class. As indicated earlier, the Company's A&E cost allocation study used both the 4 NCP and average class demands in the determination of class <u>excess</u> demands.

Q. Is there also quantitative support for the Company's selection of the 4 NCP version of the A&E demand allocation methodology for the allocation of production plant?

A. The 4 NCP version of the A&E methodology, which uses the four maximum non-coincident monthly peak demands for each customer class during the test year, was selected due to the fact that 15 of the 20 maximum 4 NCP monthly demands for the Company's five major customer classes occurred during the Company's summer peak demand months of June-September. The use of the 4 NCP demand option, rather than a lesser number of NCP demands, also prevents the demand allocator for any customer class from being unduly influenced by any extreme demand from a given month.

Q. Does the monthly peak data provided earlier in your testimony also support the adoption of a cost allocation methodology that relies, in part, on summer month demands?

A. Yes, the data in Schedules 2-1 and 2-2 of my testimony, developed as rebuttal to Mr. Bax, provides additional information regarding the dominance of the Company's monthly demands during the June-September peak summer season of each year.

Q. After the determination of customer, energy and demand allocation factors for the various components of the Company's costs, what was the next step in the completion of the Company's class cost of service study?

A. The next step was to apply the allocation factors developed for each class to each component of rate base investment and each of the elements of expense specified in the jurisdictional cost of service study. The aggregation of such cost allocations indicates the total annual costs, or annual revenue requirement, associated with serving a particular customer class. The operating revenues of each customer class minus its total operating expenses provide the resulting net operating income of each class. This net operating income divided by the allocated rate base of each class will indicate the percentage rate of return being earned by the Company from a particular customer class. This application of allocation factors to Missouri jurisdictional costs, the aggregation of the total annual cost to each of the customer classes and a summary of the results of the Company's class cost of service study are described in detail in Mr. Warwick's testimony.

<u>The Company's Class Cost of Service Study Results</u>

Q. Referring now to the specific results of the Company's class cost of service study performed by Mr. Warwick in this case, please identify Schedule 5.

A. Schedule 5 (also Mr. Warwick's Schedule 1-1) summarizes the results of the Company's class cost of service study, indicating the rate of return being earned on the service being provided to each major retail customer class. As indicated earlier, the basic starting point for this study was the test year Missouri jurisdictional cost of service study.

Q. What general conclusions can be drawn from the information contained in Schedule 5?

A. The Residential class is providing a below average rate of return at the Company's present residential rate levels and the non-residential classes are providing above average rates of return at their current rate levels. An alternative way of stating such results is that the Residential class is paying less than its cost of service and the other customer classes are paying more than the cost of their service.

Q. Please identify Schedule 6.

A. Schedule 6 summarizes the class revenue adjustments necessary for the Company to achieve an equal rate of return from each of its customer classes. This information was developed from the cost of service data contained in Schedules 1-1 and 2 of Mr. Warwick's testimony, and is based upon the Company's present level of Missouri retail revenues.

Q. How should the information in Schedule 6 be used?

A. Before any adjustment is made to the Company's overall level of revenues in this case, the revenue levels of each customer class should initially be adjusted up or down by the amounts indicated in the revenue adjustment column of Schedule 6. These revenue adjustments will result in each of the Company's customer classes providing annual revenues equal to the Company's (equal rate of return) cost of serving each of the respective customer classes. Schedule 7 of my testimony, attached hereto, illustrates the recalculation of the class cost of service study rates of return after the class revenue adjustments summarized in Schedule 6 have been applied.

Q. After establishing the revenue level of each customer class based upon cost of service, how should any subsequent adjustment in the Company's total revenue level, that may be ordered by the Commission in this case, be implemented?

A. After this initial step of moving to cost based rate levels for each customer class, any additional adjustment in the Company's total revenue should be assigned to each class on the basis of the percentage of the total net original cost rate base allocated to each customer class, as indicated on line 28 of Mr. Warwick's Schedule 2. Allocating any total Commission ordered revenue adjustment in this manner will insure that the rates of each customer class continue to reflect its fair share of the total Company revenues (recovery of costs) authorized by the Commission in this case.

The Case No. EC-2002-152 Stipulation and Agreement Revenue Adjustment

Q. On page 5 of his most recent direct testimony Mr. Watkins refers to the Unanimous Stipulation and Agreement filed on February 5, 2002, in Case No. EC-2002-152, affecting the rate design in this case. Do you agree with Mr. Watkins regarding this point?

A. Yes, I do. The stipulation in that case provided for the Company to discontinue applying its late payment charge to the unpaid balances of deferred payment agreements negotiated with customers. The stipulation also provided for the deferred payment agreement costs currently being recovered through that charge to continue to be recovered by the Company, but through its base rate revenues instead of its late payment charge. This requires that the test year level of such costs, which was $2,058,145 for the twelve month period ending September 30, 2001, be transferred from the Company's current "other" electric revenue category to the Company's base rate revenues as a part of the development of the final rates in this case.

REBUTTAL OF TESTIMONY OF JANICE PYATTE

Staff's Proposed Class Revenue Adjustments

Q. Turning now to the direct testimony of Ms. Pyatte, on page 12 of her testimony she explains why the Company sales and revenue data used for Missouri regulatory adjustments must be billing month, rather than calendar month data. Do you agree with Ms. Pyatte on this point?

A. Yes I do. Because the Company has seasonally differentiated rates that are applied on a billing month basis, the seasonal billing month data for each individual retail rate class must be utilized for performing this work.

Q. On page 14 and Schedule 5 of her testimony, Ms. Pyatte describes a format for an internal report she is recommending be developed by Ameren for use in future regulatory cases. Please comment.

A. The Company agrees with Ms. Pyatte that a report of this nature would be helpful to both the Staff and Company in future rate and regulatory work, and has initiated its development. A sample rollout of this report is attached hereto as Schedule 8 of my testimony. The Company will continue to work with Ms. Pyatte on the details presented in this report, until it can meet her requirements in this area, as near as practicable.

Q. Turning now to Ms. Pyatte's rate design testimony, on pages 18-21 she describes a process for arriving at a distribution of the Staff's proposed revenue

decrease. Is this an acceptable process for applying any adjustment to the Company's class revenue levels that may be ordered by the Commission in this case?

A. This Staff proposal is unacceptable to the Company, for all the reasons I indicated in my rebuttal to Mr. Watkins' testimony. Rather, any adjustment to the Company's revenues should be based upon the class cost of service study performed by Mr. Warwick in this case to initially equalize class rates of return, a summary of which is attached as Schedule 7 of my testimony. Using this cost of service study for revenue adjustment purposes will insure that the appropriate operating expenses are recovered from each customer class and that an equal rate of return is earned by the Company on the facilities utilized in serving each of these customer classes. Applying this approach to the data from the much more current test year recently adopted by the Commission for this case will eliminate the need for all of the calculations associated with employing the prior stipulation, which were described on pages 19-21 of Ms. Pyatte's direct testimony.

Q. Once the annual revenue requirements are developed by this process for all of customer classes, is the design of specific rates for each class the next and final step in the overall rate development process?

A. Yes, it is, and I will describe this process in greater detail while discussing the balance of Ms. Pyatte's testimony, as well as for the alternative rate design proposals the Company is submitting in this case as rebuttal to Ms. Pyatte's proposals.

<u>Staff's Rate Design Proposals</u>

Q. Pages 23-25 of Ms. Pyatte's testimony describe the Staff's work toward the design of various demand and energy charge differentials between the Company's Large General Service and Small Primary Service Rates. Does the Company support this Staff proposal?

A. As I indicated in my rebuttal to Mr. Watkins, the Company will consider this Staff suggestion as a general rate design objective or goal for the demand and energy differential between these two similarly structured rates. However, the Company does <u>not</u> accept or support the specific values for these rates, or any of the other rate classes, which are contained in various schedules in Ms. Pyatte's testimony.

Q. Why does the Company not support the specific rate values contained in Ms. Pyatte's schedules?

A. The Company cannot support these rates for two reasons 1) they are based upon an overall level of rates which the Company is disputing and 2) they are based upon a stipulation in a prior regulatory case which encompasses a significantly aged test year, rather than on the Company's class cost of service study, performed by Mr. Warwick for the test year established by the Commission for this case.

Q. Is the Company submitting its own rate design proposals as a part of its rebuttal testimony in this case?

A. Yes, and the specifics on these proposals will be discussed later in my testimony. The Company's rate design proposals are based upon the test year Missouri jurisdictional cost of service study and the Missouri class cost of service study performed by Mr. Warwick. Developing the Company's proposals on this basis overcomes the two concerns I previously raised with regard to Ms. Pyatte's rate design proposals.

Q. On pages 25-27 of her testimony Ms. Pyatte provides information regarding the impact of the Staff's rate design proposals on the rates of the Company's general categories of residential customers. Please comment.

A. While I have no quarrel with the accuracy of this portion of Ms. Pyatte's testimony, I would like to point out that such comparisons of absolute rate values do not provide the complete picture of a utility's overall performance. For example, utility system peak and seasonal load shapes, generation plant makeup, urban or rural service area and its mix of customer classes and revenue sources can all have an impact upon a utility's basic cost structure and the revenue requirement which must be recovered through its rates.

The Trends of Midwest Electric Rates

Q. Setting the absolute rate values studied by Ms. Pyatte aside, is there other information that should be considered by the Commission in setting the overall level of the Company's rates?

A. I believe that the trend of the Company's overall rates and charges, in comparison to those of other utilities in the Midwest, is also an important consideration. Such trends provide an indication of the relative operational efficiencies achieved by various utilities within the same geographic areas over a similar period of time.

Q. Are you presenting any such trend analyses as a part of your rebuttal testimony?

A. Yes, I am presenting Schedule 9, which compares the trends in rates for the Company's Missouri rates and those of several other Midwestern companies as a group during the period of 1994-2001, which starts with the year prior to the implementation of the first alternative regulation plan in Missouri.

Q. What was your source for this information?

A. I used rate information collected from each utility across the country by the Edison Electric Institute (EEI) for this purpose, as it is my department's responsibility to provide such data to EEI. We used EEI's West-North-Central region (Iowa, Kansas, Minnesota, Missouri, South Dakota and North Dakota) and the East-North-Central region (Indiana, Michigan, Ohio and Wisconsin) for these comparisons.

Q. What does this information in Schedule 9 show regarding the trends in electric rates for UE in Missouri and within each of these other Midwest areas?

A. Schedule 9 shows that the rates paid by the Company's various Missouri customer classes were from 6.2% to 8.7% less (averaging 6.8% less) in 2001, than in 1994, the year before the alternative regulation plan commenced in Missouri. By contrast, the West-North-Central area rates increased by 0.7% over this same period, while the East-North-Central area dropped by an average of 5.8%. In summary, this data indicates that the Company's customers in Missouri realized a larger reduction in the actual rates paid during this period than did the customers of other Midwest utilities, based upon the averages for their areas.

Q. Was data similar to that in Schedule 9 previously submitted to the Commission by the Company?

A. Yes, this data actually updates the data originally presented in Table 4 of the White Paper of Incentive Regulation: Assessing Union Electric's Experimental Alternative Regulation Plan that was filed with the Commission in Case No. EM-96-149 on February 1, 2001. This data is also referred to in the rebuttal testimony of Mr. Baxter.

The Company's Class Revenue Proposals – Based Upon Current Total Revenue

Q. Earlier in this testimony you provided reasons why the class rate values contained in Ms. Pyatte's schedules should not be adopted, and stated that you would submit rate proposals based upon the results of its class cost of service study. Why are the equal rates of return for all customer classes, embedded in this study, an appropriate starting point in the design of electric utility rates?

A. There are several reasons why equal class rates of return are appropriate. First and foremost is the consideration of equity and fairness to all electric customers. As total costs must ultimately be recovered, to overcharge one customer class in order to subsidize another class is both inequitable and patently unfair to the customer class or classes being overcharged.

A second important consideration in support of equal class rates of return is the cost effective utilization of electricity by customers. To make appropriate decisions regarding the most efficient and effective use of electricity, as well as the acquisition of electrical consuming equipment, customers require correct and appropriate price signals from the Company's electric rates.

A third consideration is that of competition. Cost-based electric rates are essential for the Company to compete effectively with alternative fuels, co-generation and with other electric utilities for new commercial and industrial customers.

Q. What was the source of the cost data that was used by the Company in the design of the rates it is proposing in this case?

A. The costs from the Company's class cost of service study, performed by Mr. Warwick in this case, was the source of the costs used for such purposes. The details of these class allocations were presented in Schedule 1 of Mr. Warwick's cost of service testimony in this case.

Q. Was the study in Mr. Warwick's Schedule 1 also the source of the various customer, energy and demand-related costs used in the design of the Company's proposed rates?

A. Yes, it was. Mr. Warwick, at my request, performed a more detailed analysis of such costs and segregated them into the customer, energy and the demand-related cost categories of the production, transmission and distribution functions for each customer class. This detailed sub-aggregation of costs into these categories is contained in Schedule 3 of Mr. Warwick's rate design testimony in this case, and is also included as Schedule 10 of my testimony.

Q. Was the billing unit data in Mr. Pozzo's testimony also used in the design of the Company's proposed rates?

A. Yes, the data contained in Schedules 1-6 of Mr. Pozzo's testimony in this case was used as a resource for the individual class billing units. They are based upon the Company's weather normalized sales during the test year in this case.

Class Rate Customer Charge Concepts

Q. Before describing the Company's specific rate design proposals in this case, please comment on the general development of the Customer Charge contained in each of the Company's current and proposed rate schedules.

A. The basic premise of customer-related costs is that such costs vary with the number of customers being served within a particular customer class, and bear no relationship to the energy or demand associated with the electrical consumption of the customers in each rate class. Therefore, the Company's proposed Customer Charge for each of its major rate classes was developed based upon the segregated customer-related costs for each class, developed by Mr. Warwick in his Schedule 3, and appearing in my Schedule 10.

Q. What is the result if the Customer Charges for each customer class are not set at a level sufficient to recover the full level of customer-related costs?

A. Where a monthly customer charge is not established at a level sufficient for a utility to collect the full level of its customer-related costs, the shortfall in the recovery of such costs has been typically collected in the initial energy block of a utility's rate structure, or in the demand charges of the larger non-residential customers. While this form of cost recovery provides the utility with the opportunity to recover any shortfall in customer-related costs, the recovery of customer-related costs which are, by their basic nature, fixed costs results in rate structures which are unnecessarily unfair and inequitable to various customers within each customer rate class.

Q. Why is the recovery of fixed customer-related costs through some form of usage, such as measured energy or demand units, inequitable to various customers within each of the Company's rate classes?

A. Fixed monthly customer-related costs are relatively uniform and equivalent among customers within the same rate class. Thus, recovering such costs based upon customer usage is not equitable to all customers within a given rate class, because this shifting of non-consumption related costs from a flat monthly charge basis to a consumption related charge within the rate structure, i.e. kilowatthour or demand charges, results in above average use customers subsidizing below average use customers. Another disadvantage of recovering fixed customer related costs on a variable basis is that abnormally warm or cool weather will result in an under or over recovery of such costs. For these reasons, Customer Charges within each customer class should be established to recover fixed customer-related costs as closely as possible, as are the Customer Charges contained in the rates proposed by the Company in this case.

<u>Union Electric Company Rate Design Proposals</u>

Q. Please describe the general approach used in the preparation and design of the rates being proposed by the Company in this case.

A. For each rate class, we began with the functional cost breakdowns of the class cost of service study results prepared by Mr. Warwick, which appear in Schedule 10 of my testimony. The Residential customer related costs in that schedule were increased by $2,058,145 to reflect the requirement of the Stipulation and Agreement in Case No. EC-2002-152 that these late payment related costs become a part of the Company's base rate Residential revenues. The remaining costs in Schedule 10 are those required to be recovered from the customer, energy and demand charges within each customer class, as a part of the Company's overall rate design structure for each class.

Proposed Residential Rate

Q. How was the Residential Rate being proposed by the Company in this case developed and designed?

A. Referring to my Schedule 10, the total annual Residential revenue target of $867.1 million was increased by the $2,058,145 to reflect the transfer of the late payment cost recovery, referred to above, to a total of $869.1 million. As the monthly Customer Charge was the initial rate component developed for the Residential Rate, the annual customer related cost associated with the Residential class of $130.2 million was also increased by the $2,058,145 of late payment cost recovery, to arrive at a total annual customer related cost of $132.2 million. A Customer Charge of approximately $11.33 per month was determined by dividing this annual total customer related cost by the annual number of residential customer bills.

Q. What have been the historic levels of the Company's monthly Residential Customer Charge?

A. A Residential Customer Charge of $5.75 per month was in effect in Missouri for about 15 years, from April 1985 to March 2000, when it was increased to its current level of $7.25 per month. It has remained at the $7.25 per month level since that time.

Q How was the proposed Residential summer kilowatthour charge determined?

A. The Residential Class energy related production cost of $199.5 million, indicated in my Schedule 10, was divided by the annual kwh within the Residential class to arrive at an average variable production cost of 1.732 cents per kilowatthour. The remaining cost component of the summer kilowatthour charge is related to the annual production, transmission and distribution demand related costs, which total $537.4 million. Based on the Company's historic position regarding the allocation of such annual costs, 60% of such costs, or $322.4 million, was allocated to the Company's summer billing season of June-September. The remaining 40% of such costs, or $215.0 million, were allocated to the winter billing season of October-May. The summation of these customer, energy and demand related costs established a rate of 9.48 cents per kilowatthour for the Company's summer billing period.

Q. How were the proposed Residential winter kilowatthour charges determined?

A. The design of the winter portion of the Residential Rate is more complex than the summer season rate due to the existence of two rate steps, or blocks, in the existing Residential Rate. In order to maintain existing rate relationships between the demand related production, transmission and distribution costs in the existing initial and end-step rate blocks, I first deducted the current variable cost of 1.732 cents per kilowatthour from each block and determined the ratio of the remaining demand related portion of each existing rate block to be 1.87 to 1.00. Using this relationship and the 40% portion of current demand related costs assigned to the winter from my Schedule 10, I then determined the demand rates applicable to each winter rate block to be 3.68 and 1.97 cents per kilowatthour, respectively, for the initial and end step of the Residential Rate. Adding back the current variable cost of 1.732 cents per kilowatthour to each of these values resulted in the final Residential winter rates of 5.41 cents per kilowatthour for the initial block (0-750 kilowatthours per month) and 3.70 cents per kilowatthour for the end-step rate block applicable to all kilowatthours over 750 per winter billing month.

Q. Will the rate values determined by such a process be the final rate values proposed by the Company in this case?

A. Normally some rounding up or down of these calculated rate values will be necessary to get as reasonably close to an established revenue target as possible without substantially exceeding or falling short of this target. In the case of the target established by my Schedule 10 for the Residential Class, I elected to lower the Customer Charge from the calculated amount of $11.33 to $11.30 per month in order to avoid exceeding the established target for the recovery of the total annual cost associated with residential service. The summary of these calculations and "proof of revenue" for the Residential class is attached as Schedule 11 of my testimony.

Proposed Small General Service Rate

Q. How was the Small General Service Rate being proposed by the Company in this case developed and designed?

A. The steps employed in the development of the Small General Service (SGS) Rate were generally the same as those for the Residential Rate. Maintaining the approximate two to one ratio between the single phase and the three phase Customer

Charge within this rate classification, the cost of service study analysis established single phase Customer Charge at $12.75 per month and the three phase Customer Charge at $25.50 per month.

Q. Were the rates for the energy blocks in the SGS Rate also determined in a manner similar to that described for the Residential Rate?

A. Yes, having established the above Customer Charges, the accompanying summer kilowatthour charged was determined to be 8.46 cents per kilowatthour and the initial and end-step winter rates were determined to be 4.59 and 2.90 cents per kilowatthour, respectively. The application of these charges to the billing units in the SGS Rate class will result in annual revenue of $216.5 million, which is the target revenue for the SGS class in Schedule 10 of my testimony. The summary of these calculations and "proof of revenue" for the SGS class is attached as Schedule 12 of my testimony.

Large General Service (LGS) and Small Primary Service (SPS) Rates

Q. Please describe the current structure of these two rates.

A. The structures of these rates, which are applicable to the Company's larger commercial and industrial customers, are virtually identical, as the service provided to such customers varies only by the delivery voltage and meter location. The SPS customers receive their service, and are normally metered, ahead of any transformer voltage reduction, and the LGS customers receive their service and are metered after the transformer voltage reduction. Each of these rates consist of a monthly Customer Charge, a monthly distribution Demand Charge and monthly Energy Charges which reflect both production demand and energy costs, as well as transmission demand costs. The Energy Charges within each of the three load factor-based rate blocks are seasonally differentiated to more closely track the costs of providing service to these demand metered customers.

Q. How were the Customer Charges for these rates determined?

A. The Customer Charges for the LGS and SPS Rates were determined in the same manner described earlier in my testimony for the Residential and Small General Service Rates. The customer related costs for the LGS and SPS Rates included in Schedule 10 of my testimony, $8.8 million and $1.5 million respectively, were divided by the number of annual bills rendered to the customers within each rate class to arrive at a LGS Customer Charge of $89.46 per month and a SPS Customer Charge of $190.20 per month. Generally, the LGS Rate Customer Charge will be less than the SPS Customer Charge, when both are determined in this manner, due to the higher cost of primary metering.

Q. What was the next step in the development of the LGS and SPS Rates?

A. The Schedule 10 distribution demand costs for each of these rates were analyzed with the billing demand units for each rate class in order to design the Demand Charge for each class. The current seasonal differentials of each class were such that summer demand charges were 2.7 to 2.8 times the winter demand charges. The demand charges in the cost of service based rates being designed in this case were established based upon the summer season demand charge set at twice the winter season demand charge. The resulting monthly Demand Charges for LGS were $4.94 per kilowatt and

$2.47 per kilowatt, for summer and winter respectively, and the comparable monthly Demand Charges for SPS were $4.04 per kilowatt and $2.02 per kilowatt. The LGS Rate Demand Charge will generally be greater than the SPS Demand Charge, when both are determined in this manner, due to the additional cost of transformation and some low voltage distribution facilities included in the LGS costs, but not required and used by the SPS customers.

Q. **Earlier you stated that the kilowatthour energy charges in these rates were designed to reflect the recovery of both production demand and energy costs, as well as transmission demand costs. Is this rate structure continued as a part of the LGS and SPS Rates?**

A. Yes, it is as this structure, which is generally referred to as a "load factor" or "hours use" rate structure, has been a part of the Company's LGS and SPS Rates since the late 1980's. This form of rate structure is an appropriate methodology for applying the various energy block rates that are based upon charges that reflect the cost of serving large customers with varying monthly load factors.

Q. **Please elaborate on the concept of a customer load factor base rate.**

A. Generically, a load factor based rate refers to a rate structure which has been designed to track the different levels of cost associated with supplying service to non-residential customers having varying levels of operating hours (i.e. load factors) during each billing period. The rate steps associated with such rate schedules are normally structured in ranges or blocks of kilowatthours per kilowatt of demand, or simply "hours use" (HU) of demand.

Q. Please provide an example illustrating these concepts of load factor and hours use of demand.

A. Assume two customers have equal monthly peak demands of 100 kilowatts. Customer A consumes 20,000 kilowatthours in a 30-day billing period, which contains a total of 720 (30 x 24) total hours. Customer B, operates more hours during this period and consumes 40,000 kilowatthours. Customer A's hours use of demand is 200 (20,000/100) and has a monthly load factor of 0.278 (200/720), or 27.8%. Customer B's hours use of demand is 400 (40,000/100) and has a monthly load factor of 0.556 (400/720), or 55.6%. In this example, Customer B operates the same total level of electrical consuming equipment as Customer A, but operates it for twice the average number of hours during the month as Customer A, thereby resulting in both hours use and load factor which are double that of Customer A's.

Q. Please describe the general structure of the existing LGS and SPS Rates which the Company is maintaining, and the basis for this specific rate structure.

A. These existing rate structures both currently contain identical kilowatthour per kilowatt, or hours use energy rate blocks in the following monthly ranges of hours use: (0-150), (150-350) and (All in excess of 350). As a single shift non-residential customer would operate approximately 160 (40 x 4) hours per month, a two shift customer, 320 hours per month, and more continuous operations well above these hours, this form of rate structure is the most appropriate design for establishing and reflecting the costs of serving the customers on these rates having varying hours of operation. In addition, as the Company limits its on-peak hour rate provisions to the (10 a.m. to

10 p.m.) time periods on weekdays (60 hours per week), this structure will insure that any usage billed in the over the 350 hours use block will be off-peak (weekend or third shift) electrical usage.

Q. **How were the specific rate values determined for the recovery of the LGS and SPS Rate demand related production and transmission costs, in the energy based HU blocks?**

A. The relationship of the load factors and coincident factors of the customers in these classes, included in the Company's load research program, was summarized and is illustrated in the graph contained in Schedule 13 of my testimony. The demand related generation and transmission costs previously allocated to these classes were summed and allocated 60% to summer and 40% to winter as were all other demand related costs in the Company's analyses, for the reasons previously explained in my testimony. The next step in the process was to determine the cost per kilowatt of coincident demand within each season, and to convert these costs to a cents per kilowatthour charge at the load factors associated with the Company's proposed Hours Use rate blocks in these two rates.

Q. **What are the load factors associated with the Company's LGS/SPS rate structure?**

A. These load factors can be related to a 30-day month that contains a total of 720 hours (30 x 24). For example a customer with zero usage for the month would have a zero load factor (0/720). A customer with steady hourly usage all during the month would have a 100% load factor (720/720). The HU blocks in the Company's

LGS/SPS rates break at 150 HU, or about 21% load factor (150/720), and 350 HU, or about a 49% load factor (350/720).

Q. What is the final steps in converting the coincident demand costs for each season into a cents per kilowatthour charge for each of the rate blocks in these rates?

A. The first step is to convert the seasonal demand costs into cents per kilowatthour seasonal costs at each of the Company's HU load factors. For example a $14 per kilowatt demand cost will convert to a 4 cent per kilowatthour cost at 350 HU (1400/350). The final step is to use the mathematical customer load factor/coincident factor relationship in my Schedule 13 to obtain the coincidence factor associated with the load factors represented by each of the HU rate blocks. Multiplying each of the cents per kilowatthour costs by their associated coincidence factors will establish the average rate to be charged at these levels. Thereafter, algebraic equations are used to obtain the final rates for each HU blocks that result in the appropriate charge within each HU block in order to follow the previously determined cost function for each billing season.

Q. Why does the application of coincidence factors at these HU levels, to the cents per kilowatthour demand related costs at these same HU levels, result in an appropriate assignment of demand costs at each of these points?

A. This process establishes the appropriate responsibility for demand related cost at these HU, or load factor levels, because it is applying the coincident demand cost responsibility factor to the cents per kilowatthour cost developed based upon coincident demand cost.