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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2007-0002

DIRECT TESTIMONY

OF

WILBON L. COOPER

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

St. Louis, Missouri
July, 2006

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DIRECT TESTIMONY

OF

WILBON L. COOPER

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Wilbon L. Cooper. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri.

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

A. I am employed by Ameren Services as the Manager of the Rate Engineering and Analysis Department. The Rate Engineering and Analysis Department performs services for the Ameren operating companies, including Union Electric Company d/b/a AmerenUE ("AmerenUE" or the "Company").

Q. Please describe your educational background and employment experience.

A. My educational background consists of a Bachelor of Science degree in Electrical Engineering from the University of Missouri-Rolla.

I was employed as an Assistant Engineer in the Rate Engineering Department of Union Electric in June 1980. My work included assignments relating to the general analyses and administration of various aspects of Union Electric's electric, gas, and steam rates. In October 1989 I was appointed Supervising Engineer – Rate Analysis, in the Rate Engineering Department of Corporate Planning at Ameren Services Company. In the latter position I was responsible for meeting the analytical requirements of the Company's retail

gas and electric rates and wholesale electric rates, including load research and various cost of service and rate design studies, as assigned. I was appointed to my present position of Manager of Rate Engineering and Analysis in March 2003.

I currently have responsibility for the general policies and practices associated with the day-to-day administration and design of AmerenUE's electric and gas rate tariffs, riders and rules and regulations tariffs on file with the Missouri Public Service Commission and in the participation in various proceedings before this regulatory agency. I also have these same responsibilities for Ameren's Illinois utilities under the jurisdiction of the Illinois Commerce Commission. In addition, Rate Engineering is responsible for conducting class cost of service and rate design studies and the participation in other projects of a general corporate nature, as requested by the Director of Regulatory Policy and Planning.

I have previously submitted testimony before the regulatory commissions of Illinois, Missouri, and Iowa.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony discusses: a) the revenue increase being proposed for the Company's electric retail rate classes; b) the development and results of a class cost of service study being submitted in connection with the direct testimony of AmerenUE witness William W. Warwick as part of this case; c) the design and development of the individual class rates; and d) certain other miscellaneous tariff revisions filed as part of this case. I have summarized my testimony and the testimony of Mssrs. Pozzo and Warwick in Attachment A attached hereto.

Q. Have you prepared or have there been prepared under your direction and supervision a series of schedules for presentation to the Commission in this proceeding?

A. Yes. In addition to Attachment A mentioned above, I have prepared 15 schedules. The first three, discussed immediately below, provide a good summary of the rate increase requested in this case. I discuss the remaining schedules throughout my direct testimony.

Q. Please identify Schedule WLC-E1.

A. Schedule WLC-E1 consists of sixty-eight (68) tariff sheets, which reflect the revised rates and miscellaneous tariff revisions being proposed by the Company for approval by the Commission in this proceeding. These tariffs, taken as a whole, would provide an increase in the Company's net Missouri jurisdictional normalized test year revenue of approximately $360.7 million, or 17.7%, over the annualized test year (12 months ending June 30, 2006) revenue realized from the tariffs which are effective at the time of filing.

Q. Please identify Schedule WLC-E2.

A. Schedule WLC-E2 shows the distribution of the proposed net revenue increase to the Company's various proposed rate service classifications, resulting from the proposed tariffs in Schedule WLC-E1, excluding gross receipts taxes levied on customer billings by the various municipalities within the Company's service area.

Q. Please identify Schedule WLC-E3.

A. Schedule WLC-E3 illustrates the effects of the proposed rates in Schedule WLC-E1 upon typical monthly bills of customers served under the Company's rate service classifications.

III. CLASS COST OF SERVICE STUDY

A. 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 its service. The current customer classes are Residential, Small General Service (SGS) and Large General Service (LGS) (all of which have their service delivered at a low secondary voltage level), Small Primary Service (SPS) and Large Primary Service (LPS) (delivery at a high voltage level) Large Transmission Service (LTS) (delivery at a "transmission" 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 that reflects cost causation. The results of a class cost of service study with equalized rates of return are often referred to as "class revenue requirements". Mr. Warwick conducted a class cost of service study for this case under my supervision, and he is sponsoring that study in direct testimony filed in this proceeding.

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

A. These study results are typically used to target the level of annual revenue that 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 kilowatt hour 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 kilowatt hour (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 SPS, LPS and LTS 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 targeted annual revenue requirement 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 WLC-E4 of my testimony is a simplified diagram illustrative of the AmerenUE 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 WLC-E4, 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. The 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. The lower voltages are achieved through the use of numerous line transformers located at or near the 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 SGS and LGS 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. Additionally, the Company serves its only current LTS customer at 161 kilovolts (kV) via a unique transmission service arrangement.

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

A. Yes. Those 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.

B. Costs and Revenues in Class Cost of Service Study.

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 or Federal Energy Regulatory Commission (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 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 cost based 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 discussed in the direct testimony of AmerenUE witness Gary S. Weiss, 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 study 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 is 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 (kilowatt hours) 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 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.

C. <u>Cost Allocations.</u>

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 (kilowatt hour) 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 coincident peak (CP) basis as that methodology is consistent with the method utilized for cost responsibility of the demands of the Ameren operating companies and all of the other utilities participating in the Midwest Independent Transmission System Operator, Inc. ("MISO"), per the MISO 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. 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:

Peak Responsibility – 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.

Non-Coincident Peak – 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.

Average and Excess Demand (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 (kilowatt hours ÷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) (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 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 amount of capacity the Company must add to its generation system to provide for its customers' maximum demands. However, the type of capacity (base, intermediate or peaking) which the Company must add is not dictated by maximum customer demand alone, but also by the annual energy, or kilowatt hours, 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 kilowatt hours 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 excess 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. Yes. 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 six 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. 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, at equalized rates of return 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 direct testimony.

D. Study Results.

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 WLC-E5.

A. Schedule WLC-E5 (also Mr. Warwick's Schedule WMW-E1) summarizes the results of the Company's class cost of service study, indicating the rate of return on rate base currently 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 WLC-E5?

A. The Residential and Large Primary Service classes are providing below average rates of return, while all other classes are providing above average rates of return. Overall, as is suggested by the filing of this case, the Company's is earning an inadequate return on its rate base.

E. Class Revenue Proposals.

Q. Please identify Schedule WLC-E6.

A. Schedule WLC-E6 summarizes the class revenue requirements necessary to give the Company an opportunity, based upon test year figures, 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 WMW-E1 and E2 of Mr. Warwick's direct testimony, and is based upon the Company's proposed level of Missouri retail revenues.

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

A. If one were to base class rates solely on class costs of service and ignore other relevant factors, the response is yes. However, the results of Mr. Warwick's study produced the following revenue increase by customer class:

Customer Class	Cost of Service Increase
Residential Service	26%
Small General Service	11%
Large General Service	8%
Small Primary Service	11%
Large Primary Service	28%
Large Transmission Service	7%

Q. Is the Company proposing the cost based class revenue requirements be utilized in developing class rates in the case?

A. No, the Company is proposing a departure from class revenue requirements or rate design being established solely the basis of equal class rates of return in its class cost of service study. The Company recognizes that other rate principles, as detailed in the testimony of AmerenUE witness Mr. Philip Hanser, may be used to guide rate design. As a

result, the Company is proposing to limit or cap the residential rate increase to 10%. Mr. Hanser provides the rationale for this proposal.

Q. Obviously, the Company's proposal to limit the proposed increase to the residential class to 10% results in a shortfall from the cost-based residential requirement established in Mr. Warwick's class cost of service study. How does the Company propose to collect this shortfall?

A. The Company is proposing to spread the residential revenue increase shortfall to the remaining non-lighting customer classes based on their proportionate share of cost-based proposed revenue requirements. This method of allocating the shortfall produces inter class rates of returns that are reasonable, and also, ensures that all classes (excepting lighting) receive an allocation of the residential revenue shortfall associated with the 10% cap.

Q. Please identify Schedule WLC-E7.

A. Schedule WLC-E7 summarizes the class revenue requirements necessary to: 1) give the Company an opportunity, based upon test year figures, to achieve its jurisdictional rate of return, 2) effectuate a limit of the residential rate increase to 10%, and 3) collect the residential revenue shortfall associated with the 10% rate cap to each non-lighting customer class based on its cost based proportionate responsibility for the Company's proposed revenue requirement.

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, were the basic source of the costs used for such purposes. The details of these class allocations were presented in Schedule WMW-E1 of Mr. Warwick's

direct testimony in this case. However, as stated above, class cost based class revenue requirements, as determined in Mr. Warwick's class cost of service study, were adjusted to effectuate the Company's proposed 10% residential rate cap.

Q. Was the study in Mr. Warwick's Schedule WMW-E1 also the basic 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 direct testimony in this case, and is also included as Schedule WLC-E8 of my testimony.

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

A. Yes, AmerenUE witness James R. Pozzo is providing direct testimony discussing billing unit data necessary to the design of the proposed rates. The data contained in Schedules JRP-E1 through E7 of Mr. Pozzo's direct 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 as discussed in the direct testimony of AmerenUE witness Richard A. Voytas.

IV. CLASS RATES

A. Class Rate Customer 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 to reflect the segregated customer-related costs for each class, developed by Mr. Warwick in Schedule WMW-E3 to his direct testimony.

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 not reflective of the basic principle of cost causation and equitable cost recovery.

Q. Why is the recovery of fixed customer-related costs through some form of usage, such as measured energy or demand units, not reflective of cost causation 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 reflective of the nature of these customer costs within a given rate class. The shifting of non-consumption related costs from a flat monthly charge basis to a consumption related charge within the rate structure, (i.e. kilowatt hour or demand charges), results in above average use customers paying a disproportionate share of these costs. 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 with due consideration of impact, as are the customer charges contained in the rates proposed by the Company in this case.

B. <u>Rate Design Proposals by Customer Class.</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 WLC-E8 of my testimony. The functional cost breakdown components for the non-residential rate classes were uniformly factored up by class to reflect the additional revenue requirement associated with each class's allocation of the residential revenue shortfall mentioned above.

These adjustments appear in my Schedule WLC-E9 and are used as a guide for the development of class rate values throughout the remainder of my testimony.

1. 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 WLC-E9, the total annual residential revenue target is $935.2 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 $100.1 million was divided by test year residential customer (i.e., bill) counts to arrive at a customer charge of approximately $8.22 per month.

Q How was the proposed residential summer kilowatt hour charge determined?

A. The residential class energy related production cost of $291.7 million, indicated in my Schedule WLC-E9, was divided by the annual kWh within the residential class to arrive at an average variable production cost of 2.207 cents per kilowatt hour. The remaining cost component of the summer kilowatt hour charge is related to the annual production, transmission and distribution demand related costs, which total $543.4 million. The Company is proposing to use the results of a study performed to allocate these costs to the summer and winter billing seasons. This type of study has been utilized in all of the Company's rate cases since 1987 and reflects analyses of summer and winter demands with an average and excess allocation method to determine summer vs. winter revenue responsibility for these costs, 60% of such costs, or $326.1 million, was allocated to the Company's summer billing season of June-September. The remaining 40% of such costs, or

$217.3 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 8.95 cents per kilowatt hour for the Company's summer billing period.

Q. How were the proposed residential winter kilowatt hour 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 2.217 cents per kilowatt hour from each block and determined the ratio of the remaining demand related portion of each existing rate block to be 2.22 to 1.00. Using this relationship and the 40% portion of current demand related costs assigned to the winter from my Schedule WLC-E9, I then determined the demand rates applicable to each winter rate block to be 3.35 and 1.97 cents per kilowatt hour, respectively, for the initial and end step of the residential rate. Adding back the current variable cost of 2.217 cents per kilowatt hour to each of these values resulted in the final residential winter rates of 5.57 cents per kilowatt hour for the initial block (0-750 kilowatt hours per month) and 3.73 cents per kilowatt hour for the end-step rate block applicable to all kilowatt hours 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 WLC-E9 for the residential class, I elected to lower the customer charge from the calculated amount of $8.23 to $8.22 per month in order to get relatively close to revenue requirement established for residential service. The summary of these calculations and "proof of revenue" for the Residential class is attached as Schedule WLC-E10 of my testimony.

Q. Is the Company proposing any other revisions to Residential Service classification tariff?

A. Yes, the Company is proposing to modify its definition of a residential customer to promote better administration and ease of customer understanding of the application of this service classification. These changes are of a housekeeping nature and have no impact on customer bills.

2. <u>Proposed Small General Service Rate</u>

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

A. The steps employed in the development of the 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, as adjusted, established single phase customer charge at $9.48 per month and the three phase customer charge at $18.97 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 kilowatt hour charge was determined to be 10.40 cents per kilowatt hour and the initial and end-step winter rates were determined to be 6.14 and 3.28 cents per kilowatt hour, respectively. The application of these charges to the billing units in the SGS rate class will result in annual revenue of $208.7 million, which is the approximate target revenue for the SGS class in Schedule WLC-E9 of my testimony. The summary of these calculations and "proof of revenue" for the SGS class is attached as Schedule WLC-E11 of my testimony.

3. Large General Service and Small Primary Service Rates

Q. Please describe the current structure of the LGS and SPS 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 SGS rates. The customer related costs, as adjusted, for the LGS and SPS rates included in Schedule WLC-E9 of my testimony, $5.6 million and $1.2 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 $49.50 per month and a SPS Customer Charge of $151.91 per month. These charges are lower than the existing customer charges of $66.00 per month and $210.00 per month for the LGS and SPS classes, respectively. Considering the magnitude of percentage increases for these classes, I am proposing to maintain the customer charges for these classes at the higher existing levels. It should be noted that, 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 WLC-E9 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, as adjusted, in the cost of service based rates being designed in this case were established based upon the summer season demand charge set at approximately twice the winter season demand charge. The resulting monthly demand charges for the LGS class were $5.02 per kilowatt and $2.51 per kilowatt, for summer and winter respectively, and the comparable monthly demand charges for the SPS class were $4.62 per kilowatt and $2.33 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. Additionally, the SPS rate contains a reactive power charge of 24 cents per kVAR month. This charge represents a continuation of an existing charge and is reflective of the Company's costs of corrective equipment to provide the reactive or non-working part of apparent power. Typically, the Company utilizes investment in electric capacitors to correct reactive power conditions.

Q. Earlier you stated that the kilowatt hour energy charges in these rates were designed to reflect the recovery of 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. 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 that 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 kilowatt hours 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 kilowatt hours in a 30-day billing period, which contains a total of 720 (30 x 24) hours. Customer B operates more hours during this period and consumes 40,000 kilowatt hours. Customer A's HU demand is 200 (20,000/100) and has a monthly load factor of 0.278 (200/720), or 27.8%. Customer B's HU 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 HU 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 kilowatt hour per kilowatt, or HU energy rate blocks in the following monthly ranges of HU: (0-150 HU), (150-350 HU) and (All HU 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 350 HU 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 illustrated in the graph contained in Schedule WLC-E12 to 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 kilowatt hour charge at the load factors associated with the Company's proposed HU 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 are the final steps in converting the coincident demand costs for each season into a cents per kilowatt hour charge for each of the rate blocks in these rates?

A. The first step is to convert the seasonal demand costs into cents per kilowatt hour 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 kilowatt hour cost at 350 HU (1400/350). The final step is to use the mathematical customer load factor/coincident factor relationship in my Schedule WLC-E12 to obtain the coincidence factor associated with the load factors represented by each of the HU rate blocks. Multiplying each of the cents per kilowatt hour 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 block that results 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 kilowatt hour 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 kilowatt hour cost developed based upon coincident demand cost.

Q. Once these cost tracking relationships have been determined for each of the Company's rate blocks in each of the seasons, what is the next step in the development of the LGS and SGS rates?

A. As the HU rate blocks in these rates are continuous, and the determined cost responsibilities are single-point determinations, sets of algebraic equations are set up and solved in order to derive the charges for the continuous blocks, while maintaining the derived cost responsibilities. Once these charges are determined for the production and transmission demand related costs at the primary voltage level for the SGS class, these rates were increased by a loss factor to arrive at the comparable set of rates for the LGS class.

Q. What other costs need to be added to these HU rates for the LGS and SGS rate classes?

A. The variable production energy costs need to be added to the rates for the demand related costs to arrive at the total HU energy based rates. Based upon my Schedule WLC-E9 data, these rates were determined to be 2.76 cents per kilowatt hour for the LGS class and 2.69 cents per kilowatt hour for the SPS class. These variable costs should also be added to each of the rate values determined for the recovery of demand related costs in the HU blocks, in order to arrive at the final values for this component of the Company's LGS and SPS rates being proposed in this case. Summaries of these rates and the "proof of revenue" for each class are attached as Schedules WLC-E13-1 and WLC-E13-2 to my testimony.

4. Large Primary Service Rates

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

A. The LPS Rate currently consists of a customer charge, seasonal demand and energy charges and a reactive charge. The proposed LPS customer charge was determined in the same manner described earlier in my testimony for the LGS and SPS rate customer charges. The customer related costs of $1.1 million for the LPS rate class, indicated in my Schedule WLC-E9, were divided by the number of annual bills rendered to LPS rate customers to arrive at a monthly LPS customer charge of $1,547. The existing customer charge for this class is $210.00 and in giving due consideration to rate impacts, I am proposing a customer charge of $400 for this class.

Q. How was the proposed LPS demand charge determined?

A. The design of the current LPS rate reflects a single kilowatt demand charge for each of the summer and winter billing seasons established at approximately 85% of the total production, transmission and distribution demand related cost assigned to the LPS rate class. The 15% balance of such demand-related costs was assigned to the LPS rate energy charge, along with all of the variable cost allocated or assigned to the class. This recovery of a portion of demand costs in the energy component of this rate insures that, on average, LPS class customers contribute some margin to demand related costs for every kilowatt hour sold to them.

Q. What demand and energy charges for the LPS rate resulted from the process you just described?

A. Using the functionalized demand related costs contained in my Schedule WLC-E9, I allocated 85% of such costs to the demand charge for this rate. I then determined the seasonal demand charges on the basis of the two to one ratio of the summer charge to the winter charge referred to earlier in the design of the LGS and SPS rate distribution demand charge. The monthly billing demand charges determined for the LPS rate were $19.8 per kilowatt and $9.90 per kilowatt, respectively, for the summer and winter billing months. The remaining 15% of these demand costs was assigned to summer and winter billing seasons, based upon the previously mentioned 60/40 seasonal split of such costs. These seasonal costs were then converted to a cents per kilowatt hour charge and combined with the remaining annual average variable energy cost in cents per kilowatt hour that was derived from the LPS energy related production cost in my Schedule WLC-E9. This resulted in seasonal energy charges of 3.22 cents per kilowatt hour in the summer and 2.91 cents per kilowatt hour in the winter billing season. The reactive charge in both the LPS and SPS rates was maintained at its current level.

Q. Are you proposing any additional changes to the LPS Rate?

A. Yes. The proposed LPS tariff contains a provision for a discount of 10% to the energy component of customers within this class who have demonstrated an annual load factor of at least 80% and, also a provision requiring that all primary voltage customers with demands at or above 5,000 kW be served under this classification.

Q. What is the basis for this proposed 10% energy discount?

A. As stated earlier, the proposed energy charges for the LPS class reflect the inclusion of 15% of the LPS production demand along with annual average variable energy cost that was derived from the LPS energy related production cost in my Schedule WLC-E9. The inclusion of a portion of fixed production related cost in the energy charge increases the probability that all energy delivered under the LPS tariff provides a positive contribution to margin or fixed production costs. However, cost causation principles support a lower per unit contribution to fixed costs for customers within a class demonstrating load factors noticeably higher than the class average (i.e. 69%). For example, Schedule WLC-E9 contains a fixed production related cost of approximately $81.8 million along with annual billing demands of approximately 7,517 MW for the LPS class which result in a $10.88 per kW demand charge. Converting this $10.88 demand charge to an energy rate based on a 69% load factor and a 80% load factor, results in cents per kWh realizations of 2.16¢ and 1.86¢, respectively—a difference of approximately 14%. I am proposing a 10% reduction in the energy charges to customers in the LPS class demonstrating an annual load factor of at least 80%. A summary of this rate and its "proof of revenue" is attached as Schedule WLC-E14 of my testimony.

Q. Please explain the Company's proposal to require that all primary voltage customers with a demand at or above 5,000 kW be served under this classification.

A. Currently, any customer served at a primary voltage may receive service under either the SPS or the LPS rate; however, billing provisions under the LPS rate contain a 5,000 kW minimum billing demand. Considering the Company's proposed increases of

24% and 43% for the SPS and LPS classes, respectively, and the possibility of LPS customers migrating to SPS for a potentially lower bill, it is appropriate from a revenue stability perspective to "lock-in" existing customer with demands at or above 5,000 kW to the LPS rate. Fifty-eight of the sixty-one existing SPS customers have experienced a billing demand at or above 5,000 kW.

5. Large Transmission Service Rates

Q. How was the Company's existing LTS rate developed and designed?

A. The Company's existing LTS rate was developed outside the context of a rate case and was structured and designed to be as close as practicable to the Company's existing LPS rate and to produce an annual cents per kilowatt-hour realization equivalent that would have been experienced if a customer taking service under the new LTS rate had been taking service under the existing LPS rate, taking into consideration, however, certain unique characteristics of the customer and the service it would take under the new LTS rate. Thus, the existing LTS rate can be assumed to reflect the same rate design considerations as the Company's LPS rate, excepting the introduction of an Annual Contribution Factor (ACF). The ACF accomplishes the above mentioned objective of the LTS rate producing a cents per kilowatt hour realization equivalent to billing under the LPS rate. The Commission approved the Company's LTS tariffs in Case No. EA-2005-0180, which involved an extension of the Company's service territory to include property owned by Noranda Aluminum, Inc., in New Madrid County, Missouri.

6. Proposed Large Transmission Service Rates

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

A. The LTS rate design proposed by the Company in this case mirrors the LPS proposed in this case with a customer charge, seasonal demand and energy charges and a reactive charge. Such design reflects a continuation of the existing practice of "tying" the LPS and the LTS rate. However, it should be noted that the Company is proposing to eliminate the ACF from the proposed LTS rate design as it is no longer necessary as the LTS class is now a separate class in the Company's class cost of service study. The LTS customer charge, demand charges, and energy charges were determined utilizing LTS results from the Company's class cost of service study and in the same manner as the comparable LPS charges mentioned above. The resultant charges are as follows:

Customer Charge (per month)	$400.00
Summer Energy Charge (¢/kWh)	2.94¢
Winter Energy Charge (¢/kWh)	2.69¢
Summer Demand Charge ($/kW)	$13.26
Winter Demand Charge ($/kW)	$6.63

A summary of this rate and its "proof of revenue" is attached as Schedule WLC-E15 to my testimony.

7. Lighting Rates

Q. Is the Company proposing any revisions to its street and outdoor area lighting rates in this case?

A. No specific proposals were developed for the lighting rates as a part of this case, as the Company did not perform any cost of service studies for its lighting classes, which constitute approximately 1% of the Company's total Missouri revenues. Rather, the Company accounted for its lighting costs and revenues in the cost of service study performed by Mr. Warwick by employing an approach utilized by the Commission Staff in the Company's past cases involving such studies. This approach consists of allocating all direct lighting costs and other allocated investment and expenses to the non-lighting classes, and offsetting the allocation of such costs by also allocating all lighting revenue to the same non-lighting classes in the same manner. The net effect of such allocations of costs and revenues should be negligible, under the reasonable assumption that the rates for lighting service have been established at or near their cost of service.

V. RIDERS

Q. Please explain the Company's proposed changes to Rider B – Discounts Applicable For Service To Substations Owned By Customer In Lieu Of Company Ownership and Rider C – Adjustments Of Meter Readings For Metering At A Voltage Not Provided For In Rate Schedule.

A. The Company is simply proposing to clarify the language of Rider B and Rider C to promote better administration and ease of customer understanding of the application of these Riders. These changes are of a housekeeping nature and have no impact on customer bills.

Q. Please explain the changes the Company is proposing to Rider UG – Municipal Underground Cost Recovery Rider.

A. Basically, Rider UG provides the Company the opportunity to recover its excess costs of installing underground vs. overhead facilities in situations where a municipality by ordinance or other regulation requires the Company to construct facilities underground when the Company, absent such ordinance or regulation, would construct maintain the facilities overhead. Currently, the cost recovery mechanism consists of the application of a fixed charge to the excess costs and monthly billing of that charge to the requesting municipality for a period of up to seven years. The Company's proposed revisions would apply the fixed charge rate to excess costs based on life cycle cost (i.e. total costs of owning and operating the facilities over a period of time) differences between underground and overhead and, also, allow payments to be extended for up to fifteen years with Commission approval. The recognition of potential life cycle cost differences (i.e. savings) between underground and overhead in the amount to which the fixed charge is applied between underground and overhead and, also, the ability to extend the payment arrangement, may, in some cases, afford municipalities the opportunity to underground certain overhead facilities. From a rate perspective, the Company's customers should be indifferent to this change.

VI. NON BASE RATE TARIFF CHANGES

Q. Please explain the Company's proposed addition of an "Unnecessary Trip Charge" to its Miscellaneous Charges tariff sheet.

A. The Company experiences a number of trouble (i.e. "lights out") calls from customers where our automated system of outage notification has not detected a problem on

our system that would have produced this condition. The Company's service center representatives normally communicate to these customers that we have not received an outage notification from our automated system and usually ask the customer if he/she has a problem on his/her equipment. If the response is "no", we dispatch our trouble personnel to the customer's premises and in many cases it is determined that the problem is on the customer's equipment. In said instances, our trouble personnel tell the customer that he/she will have to get someone else to fix the problem. The average cost of dispatching our trouble personnel for these trips is in excess of $50.00 dollars and we are proposing a charge of $50. If this proposal is approved by the Commission, customers will be told of the charge before our trouble personnel are dispatched and, as a result, may decide to check their equipment for problems and call the Company back if they still believe the problem is on the Company's system. This charge is being proposed for two reasons: 1) to encourage customers to check their own equipment prior to requesting that the Company dispatch trouble personnel to check the cause of the outage (i.e. deterrent) and 2) to charge an amount reflective of the costs incurred to the individuals causing those costs.

Q. Please explain the Company's proposed addition of Seasonal Reconnect language to its General Rules and Regulations.

A. The Company has performed seasonal disconnects and subsequent reconnects within a twelve month period at the request of customers served under the Residential and Small General Service classifications. The Company's existing Schedule No. 2 – Schedule of Rates for Gas Service provide for the billing of residential requests of this nature as a Seasonal Use charge equal to the reconnection charge plus the residential customer charge for any remaining month(s) of the twelve month period. The Company's customer charges

contemplate year round service and the billing of customer charges during months where seasonal service is discontinued. Therefore, the Company is proposing the addition of similar Seasonal Use tariff language for its electric operations to promote equity and consistency in the administration of billing for this activity between its electric and gas operations.

Q. Please explain the Company's proposal to modify its tariff provisions applicable to Overhead Extensions to Residential Subdivisions.

A. Currently, the Company's tariff provisions for overhead extensions to residential subdivisions provide for single phase service required for the distribution of electricity, through and within the boundaries of a residential subdivision at no cost to the customer/developer, regardless of the lot size of homes within the subdivision. While utilization of this provision is reasonable for subdivisions with lot sizes that are representative of those of "average" subdivisions, the utilization of this provision for subdivisions with extremely large lot sizes causes the Company to incur line extension costs much greater than the average per lot costs of residential subdivisions. Therefore, the Company is proposing to modify these provisions to require per lot customer/developer contributions where the average lot size exceeds 100,000 square feet and where the average frontage footing exceeds 500 feet. Additionally, the Company is proposing individual lot excess footage charges for overhead services of more than a single span or underground services of more than 250 feet. Contributions made by customers/developers under the Company's proposal will be treated as an offset to rate base and over the long term contribute to lower rates for customers. It should be noted that subdivisions within the Company's

service territory with lot sizes of this magnitude are extremely rare and, therefore, the Company expects minimal application of this proposed provision.

Q. Please explain the Company's proposal to remove all references the use of "seasonal revenues" in its Rule and Regulations provisions for line extensions.

A. Currently, the Company's tariffs permit the use of seasonal revenues (i.e. revenues associated with seasonal charges in the SGS, LGS, and SPS rates) as a possible offset to the costs of relocating distribution facilities. These provisions have been in effect for more than 16 years; however, use thereof has been extremely limited and, also, arduous from an administrative perspective. Therefore, the Company is proposing to remove these provisions.

Q. Please explain the Company's proposal to extend the deficiency payment period for line extensions in areas where Cooperative Electric Competition exists.

A. The Company's existing tariffs contain provisions for a revenue guarantee agreement where the estimated cost of distribution extension exceeds net annual revenue estimated to be received from the Company. The monthly guarantee payment to be made by customer is a minimum of 1/12 of the total cost of the extension being guaranteed. If the billed usage in a month is less than the sum of the prior months guarantee amounts less prior actual payments plus the current months' guarantee amount, then a deficiency payment is required. The Company's field personnel have indicated that the twelve-month term for deficiency payments does not allow them to effectively compete with cooperatives for new connections and, as a result, the Company is proposing to extend the payment of any one year deficiency amounts for a period of three years. This proposed change does not affect the one-year comparison of extension costs to revenues, but, instead represents a "financing"

of the deficiency for an additional two years. This proposed change should also be beneficial in the Company's ongoing efforts to obtain service territory agreements with cooperatives.

Q. Please explain the Company's proposal to remove certain single simultaneous demand or 'coincidizing" demand language from the Rules and Regulations provisions of its tariffs.

A. Each of the Company's existing non-residential tariffs contain language expressing the inability of customers to cumulate or "coincidize" usage, unless such cumulation was in effect prior to 1980. However, existing Rules and Regulations language states that "... a single simultaneous demand for billing of customer's account, provided it is feasible to do so and that the Company is not precluded from doing so by any other sections of these rules and regulations." Obviously the language in the rates is somewhat incongruent with the rules and regulations. The Company is proposing to delete the language from the rules and regulations to eliminate any confusion in this regard.

Q. Please explain the Company's proposal to modify its tariff provisions to comply with 4 CSR 240-20.050.

A. Currently, the Company's tariff provisions related to individual metering of multiple occupancy buildings are not totally consistent with the language addressing these situations in 4 CSR 240-20.050 and have resulted in the filing of numerous applications for a variance from the Company's tariff rules and regulations. Development of these variance applications are burdensome for developers and the Company and review of these applications require input from the variance Committee established by the Commission. As a whole, this process has proven to be administratively burdensome, while providing little, if any, benefit to the Company or the Commission. The Company is proposing to modify its tariffs to fully

comport with 4 CSR 240-20.050 to minimize the number of variance applications to the Commission and, thus, reduce the administration of same.

Q. Please explain the Company's proposal to modify its non-residential Billing Adjustments tariff provisions.

A. Over the last several years, the Company has experienced several disputes with non-residential customers regarding the interpretation of its billing adjustments tariff language. The Company continuously strives to produce timely and accurate bills and these disputes are rare. However, when experienced, the billing adjustment amounts can be significant for non-residential customers. Clearly, such disputes do not promote customer satisfaction and, also, result in increased administrative costs. Therefore, the Company is proposing to modify its non-residential billing adjustment tariff provisions with language that promotes better administration and customer satisfaction via ease of customer understanding of these provisions. This proposed language includes reducing the period of adjustment for certain billing adjustments from sixty months plus the current billing period to twenty four months plus the current billing period. This reduction in the billing adjustment window is more reflective of the Company's customer bill record retention period and, also, reduces the concern of customer impact where "under billings" have occurred.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	)))))	Case No. ER-2006-0002

AFFIDAVIT OF WILBON L. COOPER

STATE OF MISSOURI)
) **ss**
CITY OF ST. LOUIS)

Wilbon L. Cooper, being first duly sworn on his oath, states:

1. My name is Wilbon L. Cooper. I work in the City of St. Louis, Missouri, and I am employed by Ameren Corporation as Manager of Rate Engineering and Analysis.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Union Electric Company d/b/a AmerenUE consisting of 42 pages, Appendix A and Schedules WLC-1 through WLC-15, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Wilbon L. Cooper

Wilbon L. Cooper

Subscribed and sworn to before me this 6th day of July, 2006.

Carolyn J. Woodstock

Notary Public

My commission expires: May 19, 2008

CAROLYN J. WOODSTOCK
Notary Public - Notary Seal
STATE OF MISSOURI
Franklin County
My Commission Expires: May 19, 2008

EXECUTIVE SUMMARY

Wilbon L. Cooper

Manager of the Rate Engineering Department
Ameren Services Company

* * * * * * * * * *

The purpose of my testimony, and that of my associates, Mr. James R. Pozzo and Mr. William M. Warwick, is to address the following areas of the case:

Sales/Revenues
Class Cost of Service
Rate Design
Miscellaneous Tariff Revisions

Sales/Revenues

Sales, revenues and rate billing units, for the twelve months ending June 2006 test year, were developed by Mr. Pozzo based upon the Company's weather normalized sales and are provided in his Schedules for use in the subsequent design of final rates as a part of this case.

Class Cost of Service

Mr. Warwick has performed a fully embedded class cost of service study that produced cost of service based revenue requirements at equal class rates of return for the test year ended June 2006. Included in this study was the use of the Average and Excess 4NCP method for the allocation of fixed production costs. Generally, system peak demands and, to a major extent, excess customer demands, are the motivating factors which influence the amount of capacity the Company must add to its generation system to provide for its customers' maximum demands. However, the type of capacity (base, intermediate or

peaking) which the Company must add is not dictated by maximum customer demand alone, but also by the annual energy, or kilowatt hours, which will be required to be generated by such capacity, i.e., the generation unit's utilization factor. The 4NCP method gives proper weighting to both a) class peak demands and b) class energy consumption (average demands) which 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 kilowatt hours divided by total annual hours (8,760), and the excess NCP demands of each class. Additionally, Mr. Warwick's study further delineated the study results functionally among production, transmission and distribution and, also, classified the costs as either customer, energy, or demand related for the development of specific rates within the classes. The class revenue requirements from this study result in the following percentage increases for the Company's major customer classes: Residential 27%, Small General Service 11%, Large General Service 8%, Small Primary Service 11%, Large Primary Service 29% and Large Transmission Service 7%.

Rate Design

While cost based rates are the starting point in developing class revenue targets and rate design, there are other factors (e.g. public acceptance, rate stability, and revenue stability from year to year) that should be considered when determining class revenue requirements and designing rates. Theses factors are more fully developed in the testimony of Company witness Mr. Hanser. Considering the cost based class revenue requirements from Mr. Warwick's study and proper consideration of the other factors developed in Mr. Hanser's mentioned testimony above, the Company is proposing to cap the residential class rate increase at 10%. The shortfall in the cost based revenue requirement of the residential class

associated with the residential rate cap proposal was allocated to the Company's remaining major customer classes based on each class' "original" cost based (i.e. at equal class rates of return) proportionate share of the total cost based revenue requirement. The class revenue requirements from this residential rate cap proposal resulted in the following percentage increases for the Company's major customer classes: Residential 10%, Small General Service 24%, Large General Service 20%, Small Primary Service 24%, Large Primary Service 43% and Large Transmission Service 19%.

Miscellaneous Tariff Revisions

The Company is proposing several miscellaneous tariff revisions that are primarily of a housekeeping nature. Tariff language changes have been proposed to improve ease of customer understanding and administration. Additionally, certain tariff changes are being proposed to address conditions of which there are very limited applications.

SERVICE CLASSIFICATION NO. 1(M)
RESIDENTIAL SERVICE RATE

*Rate Based on Monthly Meter Readings

Summer Rate (Applicable during 4 monthly billing periods of June through September)

Customer Charge - per month	$8.22
Energy Charge - per kWh	8.95¢

Winter Rate (Applicable during 8 monthly billing periods of October through May)

Customer Charge - per month	$8.22
Energy Charge - per kWh	
First 750 kWh	5.57¢
Over 750 kWh	3.73¢

Optional Time-of-Day Rate

Customer Charge - per month	$16.50
Energy Charge - per kWh (1)	
Summer (June-September billing periods)	
All On Peak kWh	12.22¢
All Off Peak kWh	5.02¢
Winter (October-May billing periods)	
All On Peak kWh	7.21¢
All Off Peak kWh	3.56¢

(1) On-peak and Off-peak hours applicable herein shall be as specified in Rider I, paragraph A.

Payments. Bills are due and payable within ten (10) days from date of bill and become delinquent after twenty-one (21) days from date of bill.

Term of Use. Initial period one (1) year, terminable thereafter on three (3) days' notice.

Tax Adjustment. Any license, franchise, gross receipts, occupation or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

*Indicates Change

SERVICE CLASSIFICATION NO. 1(M)
RESIDENTIAL SERVICE RATE (Con'd).

*1. Rate Application.

A. Service under this Rate is available for any eligible residential customer within the territory served by Company under this Schedule where power and energy used at customer's premises is for predominantly residential purposes, meeting the following criteria:

1. Single-family dwelling or building containing two or more single-family units, where each unit is separately metered and used as a residence.

2. Homes that are served by a single meter where usage is a combination of home and farm use. Usage shall be limited to service within the residence on the farm and that required for all general farming and agricultural purposes conducted on the premises served. Where separate meters are required to supply other operations, each additional meter shall be billed under the applicable non-residential rate.

3. Recreation facilities consisting of summer cottages, homes, trailers or boat slips where service is individually metered and intended for continuous use by the same single family.

B. Service under this Rate is not available to customers when power and energy would be used at customer's premises for predominately non-residential purposes. The following structures are not considered residential:

1. Multiple-occupancy club houses, recreational lodges, sorority or fraternity houses, dormitories, assisted living residences or other buildings used for group living or similar activities, where individual units are typically not metered separately.

2. A residence or dwelling unit whose occupants are expected to be transient in nature.

3. Single-metered service supplied to multiple occupancy buildings for which a Commission variance, from the separate metering requirement contained in Section V.L. Rent Inclusion of the Company's rules and regulations, has been granted.

2. Character of Service Supplied. Company will specify and supply one standard single-phase and, for additional residential requirements, one three-phase secondary service voltage under this Service Classification, which service will be cumulated for billing purposes.

*Indicates Change.

SERVICE CLASSIFICATION NO. 1(M)
RESIDENTIAL SERVICE RATE (Con'd).

* Unless otherwise required for Company's engineering or other reasons, any additional service requested by customer will be provided, subject to the Company's approval, under the provisions of Section III.Q - Special Facilities. Such additional service, if any, supplied through facilities installed on and after May 5, 1990, will not be cumulated or otherwise combined for billing purposes with any other service supplied to customer.

*3. Temporary Service. Temporary service requested for residential use will be supplied under the terms and conditions set forth under Rider D.

*4. Single-Metered Multiple-Occupancy Residential Buildings. This para-graph applies only to buildings constructed and served under this provision prior to June 1, 1981. The total monthly bill to each such building to which service is delivered and metered at one point shall be equal to the total number of dwelling units therein multiplied by the bill per dwelling unit, which bill per dwelling unit shall be calculated by applying the Residential Service Rate to the average kilowatthour use per dwelling unit (equal to the total building use divided by the number of dwelling units, rounded to the nearest kilowatthour). Electrical use for common building services such as hall lights, elevators and laundry areas used exclusively by tenants may be metered and billed through the main building meter. Use for restaurants, arcade shops, retail stores, office space or any other commercial venture must be separately metered and billed on the appropriate General Service or Primary Service Rate.

The Company shall discontinue the provisions of this paragraph (4.) by December 15, 1995. Prior to this date of such discontinuance, all customers currently receiving service thereunder will be notified of such discontinuance by U. S. mail and/or personal contact. Thereafter, all such customers will be transferred to standardized billing under the provisions of Service Classifications 1(M), 2(M), 3(M), or 4(M), as applicable. To consummate this transfer to Service Classifications 3(M) or 4(M), such customers shall assume responsibility for local distribution supply facilities normally owned, installed and maintained by 3 (M) and 4 (M) customers, but previously owned, installed and maintained by Company under the provisions of this paragraph (4.). Customer shall assume responsibility in writing for such facilities previously installed by Company under one of the following options a) purchase such facilities previously installed by paying Company a lump-sum amount equal to the estimated book value (original cost less accumulated depreciation) of such facilities, or b) finance the estimated book value of such facilities with Company for any period up to a maximum of 24 months, at the interest rate referenced on Sheet No. 194,

*Indicates Reissue.

SERVICE CLASSIFICATION NO. 1(M)
RESIDENTIAL SERVICE RATE (Con'd).

* Paragraph (4.) of the Company's tariffs, or c) install its own facilities in lieu of those previously installed by Company. Any customer transferring to Service Classification 3(M) that does not make written election of one of the aforementioned options by December 15, 1995, shall nevertheless be transferred to the standard Service Classification 3(M) under the provisions of option (b) above with a 24-month finance period. However, any customer wishing to transfer to Service Classification 4(M) must make written election for one of the aforementioned options to qualify for the provisions of the 4(M) tariff. Under all such customer options, customer shall thereafter be totally responsible for all required maintenance and the subsequent replacement of such facilities, as are all other Service Classification 3(M) and 4(M) customers.

*5. Optional Time-of-Day (TOD) Service. Applicable at customer's option for all Residential Service usage, subject to the following provisions:

*a. Customer will be transferred to this TOD rate option effective with TOD meter installation and transferred from this TOD rate option to the applicable non-TOD rate after the meter is removed.

*b. Customer electing this TOD option, shall remain on said option for a minimum period of twelve (12) months, provided however, that customer may discontinue this option within the first ninety (90) days thereunder subject to the continued payment of the TOD customer charge, in lieu of any other customer charge, for the full twelve (12) month term of this option.

c. Any customer canceling this TOD option cannot thereafter resume billing under said option for a period of one year following the last billing period on the TOD option.

d. Premises with 120 volt 2-wire service, or meter locations which would make monthly meter readings unusually difficult to obtain, do not qualify for this TOD option.

*6. General Rules and Regulations. In addition to the above specific rules and regulations, all of Company's General Rules and Regulations shall apply to the supply of service under this rate.

*Indicates Reissue.

SERVICE CLASSIFICATION NO. 2(M)
SMALL GENERAL SERVICE RATE

*Rate Based on Monthly Meter Readings

Summer Rate (Applicable during 4 monthly billing periods of June through September)

Customer Charge - per month	
Single Phase Service	$9.50
Three Phase Service	$19.00
Energy Charge - per kWh	10.40¢

Winter Rate (Applicable during 8 monthly billing periods of October through May)

Customer Charge - per month	
Single Phase Service	$9.50
Three Phase Service	$19.00
Energy Charge - per kWh	
Base Use	6.14¢
Seasonal Use(1)	3.28¢

(1) The winter seasonal energy use shall be all kWh in excess of 1,000 kWh per month and in excess of the lesser of a) the kWh use during the preceding May billing period, or b) October billing period, or c) the maximum monthly kWh use during any preceding summer month.

*Indicates Change

SERVICE CLASSIFICATION NO. 2(M)
SMALL GENERAL SERVICE RATE (Cont'd.)

* Optional Time-of-Day Rate

Customer Charge - per month	
Single Phase Service	$19.00
Three Phase Service	$38.00
Energy Charge - per kWh (2)	
Summer (June-September billing periods)	
All On Peak kWh	13.65¢
All Off Peak kWh	5.57¢
Winter (October-May billing periods)	
All On Peak kWh	8.99¢
All Off Peak kWh	4.13¢

(2) On-peak and Off-peak hours applicable herein shall be as specified in Rider I, paragraph A.

Payments. Bills are due and payable within ten (10) days from date of bill.,

Term of Use. One (1) year, terminable thereafter on three (3) days' notice.

Tax Adjustment. Any license, franchise, gross receipts, occupation, or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

*Indicates Change.

SERVICE CLASSIFICATION NO. 3(M)
LARGE GENERAL SERVICE RATE

* Rate Based on Monthly Meter Readings

Summer Rate (Applicable during 4 monthly billing periods of June through September)

Customer Charge - per month	$66.00
Energy Charge - per kWh	
First 150 kWh per kW of Billing Demand	8.24¢
Next 200 kWh per kW of Billing Demand	6.61¢
All Over 350 kWh per kW of Billing Demand	3.73¢
Demand Charge - per kW of Total Billing Demand	$3.64

Winter Rate (Applicable during 8 monthly billing periods of October through May)

Customer Charge - per month	$66.00
Base Energy Charge - per kWh	
First 150 kWh per kW of Base Demand	5.08¢
Next 200 kWh per kW of Base Demand	4.39¢
All Over 350 kWh per kW of Base Demand	3.15¢
Seasonal Energy Charge - Seasonal kWh	3.15¢
Demand Charge - per kW of Total Billing Demand	$2.51

Optional Time-of-Day Adjustments

Additional Customer Charge - per Month $14.00 per month

Energy Adjustment - per kWh	On-Peak Hours(1)	Off-Peak Hours(1)
Summer kWh(June-September billing periods)	+0.88¢	-0.49¢
Winter kWh(October-May billing periods)	+0.27¢	-0.15¢

(1) On-peak and off-peak hours applicable herein shall be as specified in Rider I, paragraph A.

*Indicates Change.

SERVICE CLASSIFICATION NO. 4(M)
SMALL PRIMARY SERVICE RATE

* Rate Based on Monthly Meter Readings

Summer Rate (Applicable during 4 monthly billing periods of June through September)

Customer Charge - per month	$210.00
Energy Charge - per kWh	
First 150 kWh per kW of Billing Demand	8.06¢
Next 200 kWh per kW of Billing Demand	6.47¢
All Over 350 kWh per kW of Billing Demand	3.65¢
Demand Charge - per kW of Total Billing Demand	$4.64
Reactive Charge - per kVar	24.00¢

Winter Rate (Applicable during 8 monthly billing periods of October through May)

Customer Charge - per month	$210.00
Base Energy Charge - per kWh	
First 150 kWh per kW of Base Demand	5.02¢
Next 200 kWh per kW of Base Demand	4.33¢
All Over 350 kWh per kW of Base Demand	3.10¢
Seasonal Energy Charge - Seasonal kWh	3.10¢
Demand Charge - per kW of Total Billing Demand	$2.33
Reactive Charge - per kVar	24.00¢

Optional Time-of-Day Adjustments

Additional Customer Charge - per Month $14.00 per month

Energy Adjustment - per kWh	On-Peak Hours(1)	Off-Peak Hours(1)
Summer kWh(June-September billing periods)	+0.63¢	-0.35¢
Winter kWh(October-May billing periods)	+0.23¢	-0.13¢

(1) On-peak and off-peak hours applicable herein shall be as specified within this service classification.

*Indicates Change

SERVICE CLASSIFICATION NO. 4(M)
SMALL PRIMARY SERVICE RATE (CONT'D)

*1. Rate Application. This rate is applicable to all primary service supplied by the Company in Missouri which does not qualify for any other primary rate.

2. Character of Service Supplied. Company will specify and supply a standard three-phase alternating current primary service voltage. Where Company supplies service at 34.5 kV or higher, the appropriate adjustments under Rider B will apply.

3. Cumulation of Services. Service provided through multiple meters to the same customer on the same premises and cumulated for billing purposes under this Service Classification, prior to May 5, 1990, may continue to receive such billing. Unless otherwise required for Company's engineering or other reasons, any additional services installed at customer's request and agreed to by Company on and after May 5, 1990, will not be cumulated or otherwise combined for billing purposes with any other service supplied to customer.

4. Energy Billing. The lesser of customer's maximum monthly metered demand or Total Billing Demand shall be used to apportion customer's kilowatthours to the kWh per kW energy rate steps for billing purposes. In addition, customer's proportion of Base and Seasonal billing demands, as defined in this rate, shall be used to initially apportion customer's kilowatthours to the Base and Seasonal Energy rate steps for billing purposes during the winter billing season.

5. Demand Billing

A. Total Billing Demand. The monthly Billing Demand shall be the maximum demand established during peak hours or 50% of the maximum demand established during off-peak hours, whichever is greater, but in no event less than 100 kW.

Peak hours and off-peak hours are defined as follows:

Peak hours: 10:00 A.M. to 10:00 P.M.,
Monday through Friday.

*Indicates Change.

SERVICE CLASSIFICATION NO. 11(M)
LARGE PRIMARY SERVICE RATE

* Rate Based on Monthly Meter Readings

Summer Rate (Applicable during 4 monthly billing periods of June through September)

Customer Charge - per month	$400.00
Energy Charge - per kWh	3.22¢
Demand Charge - per kW of Billing Demand	$19.80
Reactive Charge - per kVar	24.00¢

Winter Rate (Applicable during 8 monthly billing periods of October through May)

Customer Charge - per month	$400.00
Energy Charge - per kWh	2.91¢
Demand Charge - per kW of Billing Demand	$9.90
Reactive Charge - per kVar	24.00¢

Optional Time-of-Day Adjustments

Additional Customer Charge - per Month $14.00 per month

Energy Adjustment - per kWh	On-Peak Hours(1)	Off-Peak Hours(1)
Summer kWh(June-September billing periods)	+0.45¢	-0.25¢
Winter kWh(October-May billing periods)	+0.20¢	-0.11¢

(1) On-peak and off-peak hours applicable herein shall be as specified within this service classification.

** High Load Factor Discount. Customers qualifying for service under this rate who demonstrate a minimum annual load factor of eighty (80) percent will be eligible for a ten (10) percent discount to the base Energy Charges stated above. The annual load factor ratio shall be the average annual demand to annual peak billing demand during the most recent calendar year. Where customer demonstrates to Company's satisfaction that said ratio can be reasonably expected to be achieved in the subsequent year, customer will receive the discount. Said discount shall continue in effect so long as this criterion is satisfied on an annual basis.

Payments. Bills are due and payable within ten (10) days from date of bill.

Term of Use. One (1) year, terminable thereafter on three (3) days' notice.

Tax Adjustment. Any license, franchise, gross receipts, occupation or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

*Indicates Change.
**Indicates Addition.

SERVICE CLASSIFICATION NO. 11(M)
LARGE PRIMARY SERVICE RATE (CON'D.)

*1. Rate Application. This rate is applicable to all customer's receiving primary service voltage or higher whose billing demand in any month exceeds 5000kW.

2. Character of Service Supplied. Company will specify and supply a standard three-phase alternating current primary service voltage. Where Company supplies service at 34.5 kV or higher, the appropriate adjustments under Rider B will apply.

3. Cumulation of Services. Service provided through multiple meters to the same customer on the same premises and cumulated for billing purposes under this Service Classification, prior to May 5, 1990, may continue to receive such billing. Unless otherwise required for Company's engineering or other reasons, any additional services installed at customer's request and agreed to by Company on and after May 5, 1990, will not be cumulated or otherwise combined for billing purposes with any other service supplied to customer.

4. Demand Meters. Company will install demand meters for the measurement of demands.

5. Billing Demand. The billing demand in any month will be the highest demand established during peak hours or 50% of the highest demand established during off-peak hours, whichever is highest during the month, but in no event less than 5000 kW.

Peak hours and off-peak hours are defined as follows:

Peak hours:	10:00 a.m. to 10:00 p.m., Monday thru Friday.	
Off-Peak hours:	All other hours including the entire 24 hours of the following days:	
New Year's Day	Independence Day	Thanksgiving Friday
Good Friday	Labor Day	Christmas Eve Day
Memorial Day	Thanksgiving Day	Christmas Day

All times stated above apply to the local effective time.

*Indicates Change.

MISCELLANEOUS CHARGES

A. Reconnection Charges per Connection Point

Sheet No. 106, Par. B-3 (Annually Recurring Service)	$30.00
Sheet No. 184, Par. I (Reconnection of Service)	30.00

*B. Supplementary Service Minimum Monthly Charges

Sheet No. 103, Par. C-3

Charges applicable during 4 monthly billing periods of June through September	Primary Service Rate
Customer Charge per month, plus	$400.00
All kW @	$19.80

Charges applicable during 8 monthly billing periods of October through May	Primary Service Rate
Customer Charge per month, plus	$400.00
All kW @	$9.90

C. Tax Adjustment. Any license, franchise, gross receipts, occupation or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be so designated and added as a separate item to bills rendered to customers under the jurisdiction of the taxing authority.

**D. Service Call Charge. Customer's reporting service problems may be charged a $50.00 fee for a service call, if it is determined the problem is within the customer's electrical system.

*Indicates Change.
**Indicates Addition.

SERVICE CLASSIFICATION NO. 12 (M)
LARGE TRANSMISSION SERVICE RATE

***Rate Based on Monthly Meter Readings**

Summer Rate (Applicable during four (4) monthly billing periods of June through September)

Customer Charge	$400.00	per month
Demand Charge	$13.26	per kW of Billing Demand
Energy Charge	$0.0294	per kWh
Reactive Charge	$0.24	per kVar

Winter Rate (Applicable during eight (8) monthly billing periods of October through May)

Customer Charge	$400.00	per month
Demand Charge	$6.63	per kW of Billing Demand
Energy Charge	$0.0269	per kWh
Reactive Charge	$0.24	per kVar

Optional Time-of-Day Adjustments

Additional Customer Charge	$14.00	per month

Energy Adjustment - per kWh	On-Peak Hours (1)	Off-Peak Hours (1)
Summer kWh (June-September Billing Periods)	+$0.0045	-$0.0025
Winter kWh (October-May Billing Periods)	+$0.0020	-$0.0011

(1) On-peak and off-peak hours applicable shall be as specified within this service classification.

*Indicates Change

TABLE OF CONTENTS
RIDERS

*Indicates Addition.

Rider B

DISCOUNTS APPLICABLE FOR SERVICE TO SUBSTATIONS OWNED BY CUSTOMER IN LIEU OF COMPANY OWNERSHIP

* Where a Customer served under rate schedules 4(M) or 11 (M) takes delivery of power and energy at a delivery voltage of 34kV or higher, Company will allow discounts from its applicable rate schedule as follows:

1. A monthly credit of $0.81/kW of billing demand for customers taking service at 34.5 or 69kV

2. A monthly credit of $0.95/kW of billing demand for customers taking service at 115kV or higher

*Indicates Change.

RIDER C *

ADJUSTMENTS OF METER READINGS FOR METERING AT A VOLTAGE NOT PROVIDED FOR IN RATE SCHEDULE

Where service is metered at a voltage other than the voltage provided for under the applicable rate schedule, an adjustment in both the kilowatthour and kilowatt meter readings for the applicable service will be made as follows:

For customers on rate schedule 2(M) or 3(M) taking delivery at secondary voltage:

1. Metered at Primary Voltage or higher, meter readings (kWhr and kW) will be decreased by 0.68%.

For customers on rate schedule 4(M) or 11(M):

2. Metered at 34kV or higher, meter readings (kWhr and kW) will be decreased by 0.68%

3. Metered at Secondary voltage, meter readings (kWhr and kW) will be increased by 0.68%

4. Delivered at 34 kV or higher, served through a single transformation to secondary voltage, and metered at secondary voltage, no Rider C adjustment will apply.

Company shall not be required to provide any distribution facilities beyond the metering point except when required for engineering or other valid reasons.

*Indicates Change.

RESERVE DISTRIBUTION CAPACITY RIDER
RIDER RDC

1. Purpose - The purpose of this Rider is to provide reserve capacity on the Company's distribution system to customers that request a reserve distribution service connection for the delivery of electricity from distribution facilities other than the standard or preferred distribution supply facilities designated by Company.

* 2. Applicability - This optional Rider is limited to customers who qualify for service under the Company's Service Classification 3 (M) Large General Service Rate, 4 (M) Small Primary Service Rate, or 11 (M) Large Primary Service Rate, with a minimum monthly metered demand of 500 kilowatts or greater. This Rider shall expire on December 31, 2011 and no further requests for service under this Rider will be accepted after that time. All contracts in existence as of December 31, 2011 shall remain in force per the terms of those agreements.

3. Availability - The availability of reserve distribution supply service to a customer shall be contingent upon Company's engineering studies of the impact of providing reserve distribution service to a customer and the Company's current and projected system distribution capacity needs.

4. Description of Reserve Distribution Service - When provided, Company will designate the reserve distribution capacity on its electric distribution system that will be available to the customer upon a single contingency failure of the preferred or "standard" supply to the customer. Such reserve service is subject to the following conditions:

The determination of delivery circuits and routes to provide sufficient single contingency distribution reserve capacity will be made by Company and will be subject to change as operating conditions change.

Company will make all reasonable efforts to provide reserve distribution service on an adequate and continuous basis, but will not be liable for service interruptions, deficiencies or imperfections which result from conditions which are beyond the reasonable control of the Company. The Company cannot guarantee the service as to continuity, freedom from voltage and frequency variations. The Company will not be responsible or liable for damages to customer's apparatus resulting from failure or imperfection of service beyond the reasonable control of the Company. Where such failure or imperfection of service might damage customer's apparatus, customer should install suitable protective equipment.

Company does not commit to reserve supplies from different substations and reserves the right to designate the preferred & reserve supplies and limit switching of customer's load from one service supply to the other.

*Indicates Change.

RESERVE DISTRIBUTION CAPACITY RIDER
RIDER RDC (Cont'd.)

5. Customer Requirements - The customer and Company shall contract for the level of electrical load for which the Company is providing electric distribution reserve capacity.

6. Contribution and Rates for Electric Distribution Reserve Service - The customer shall pay, in advance of construction, to Company its estimated cost to extend or reinforce the reserve portion of the additional distribution supply back to a point on the Company's system where the Company reasonably expects adequate distribution capacity will exist. Said payment shall be non-refundable. If the customer's load increases above their contracted capacity, and/or they request additional reserve capacity for new load and the Company must install additional distribution reserve capacity facilities, an additional customer payment will be required. Said payment shall be in advance and be equal to the Company's total estimated costs as described above to modify or expand Company's distribution system to accommodate the increased load. The cost of all transformers and switchgear included as part of the reserve capacity shall include the estimated costs to install and remove said facilities.

Additionally, the following monthly rates for electric distribution reserve capacity shall apply, based on the lowest voltage level at which distribution reserve facilities are provided, regardless of the voltage of the customer's standard or preferred supply.

*

For Second Supply Voltage of:	Monthly Rate per kW of Billing Demand (Same Billing Demand As Metered and Delivered Via Customer's Designated Standard Connection)
120 - 600 volts	Large General Service Total Billing Demand Charges
601 - 15,000 volts	Small Primary Service Total Billing Demand Charges
15,001 - 69,000 volts	Small Primary Service Total Billing Demand Charges less Rider B Demand Discount Credit (Item 1)
69,001 - 345,000 volts	Small Primary Service Total Billing Demand Charges less Rider B Demand Discount Credit (Item 2)

7. Duplicate On-Site Supply Facilities - Requests for duplicate supply facilities on the customer's premises, such as a second transformer or a second primary extension from a single supply feeder, shall be provided under provisions of the Company's Special Facilities tariff, Section III.Q.

8. Term - Customer shall be required to sign a contract for an initial term of ten (10) years, cancelable by customer at any time after one (1) year with six (6) months' written notice to Company. Absent such

*Indicates Change.

RIDER UG
MUNICIPAL UNDERGROUND COST RECOVERY RIDER

APPLICABILITY:

* If any Municipality or other governmental subdivision (hereinafter referred to as the "Municipality") by ordinance or other regulation requires Company to construct lines and appurtenances or other facilities designed for any Distribution or Transmission voltages (hereinafter referred to as "facilities") underground for any new or existing facilities in the Municipality when the Company, absent from such ordinance or regulation, would construct or continue to maintain the facilities overhead, and where the recovery of the additional cost for such underground is not otherwise provided for in the Company's General Rules and Regulations Applying to Electric Service, the estimated additional life cycle costs required by the Company to construct, operate and maintain the facilities underground shall be assessed against the Municipality.

Before Company starts placing any facilities underground pursuant to this Rider, the Municipality shall provide adequate assurance to Company that the Municipality's obligations to pay for such facilities are valid, lawful, and enforceable against the Municipality.

INVESTMENT RECOVERY:

The following shall be used in determining and recovering the additional investment from each Municipality:

*1. The Company shall estimate the life cycle costs of the underground facilities and the life cycle costs of equivalent overhead facilities and shall provide these estimates to the Municipality to aid the Municipality in determining whether to proceed with the undergrounding of the facilities.

*2. Where underground facilities will not replace existing overhead facilities, any estimated life cycle costs of underground facilities in excess of the estimated life cycle costs of overhead facilities, plus the cost of estimating the life cycle costs of both facilities, shall be the additional investment.

*3. Where underground facilities will replace existing overhead facilities the estimated life cycle costs of underground facilities, plus all costs associated with the retirement of the existing overhead facilities, plus the costs of estimating the underground facilities' life cycle costs and retirement of the existing facilities, shall be the additional investment. The costs associated with retirement of the facilities shall include all costs associated with removal, as well as the original cost of such facilities, less accrued depreciation and salvage value.

*Indicates Change.

RIDER UG
MUNICIPAL UNDERGROUND COST RECOVERY RIDER

*4. The length of the recovery of this additional instrument will be fifteen years or such terms as agreed by the Municipality and the Company from the date of installation of each underground project. For recovery periods greater than fifteen years, the Company must file for Commission approval.

*5. Monthly charges under this Rider shall be calculated by multiplying the additional life cycle costs by the Company's monthly fixed charge rate in effect as of the date the first monthly charge associated with that additional investment was billed. The monthly fixed charge rate shall include a component for equity return, debt return, depreciation, taxes, property taxes, and administrative and general expenses. Monthly charges shall be shown as a separate line item on the monthly electric bill of the Municipality. If the Municipality does not take electric service from the Company, the Company shall render monthly bills for the charges to the Municipality.

The monthly fixed charge shall be determined as follows:
Where:

$$FC = PVRR \times \left[\frac{i}{1-(1+i)^{-N}} \right] \div 12$$

FC = Levelized fixed charge

$$PVRR = \sum_{T=1}^{N} Revenue\,Requirement_T \left(\frac{1}{1+i} \right)^T$$

PVRR = Present Value of Annual Revenue Requirements

i = Composite Return (overall after-tax rate of return)

N = Number of years

T = Year

$Revenue\ Requirement_T$ = Dbt + Pfd +Eq + Dpr + Tax + PropTax + A&G

Dbt = Return on Debt
Pfd = Return on Preferred
Eq = Return on Common Equity
Dpr = Return of investment, depreciation
Tax = Current & Deferred Income Taxes
Prop Tax = Property Taxes
A&G = Administrative and General

*Indicates Change.

RIDER UG
MUNICIPAL UNDERGROUND COST RECOVERY RIDER

*6. The monthly charge will appear on bills rendered to the Municipality 30 days after placing in service the first facilities for each project that are subject to that Municipality's ordinance or regulation in service. The monthly charge shall be wholly based on estimated costs. The amount of the monthly charge shall be reviewed and adjusted at least once annually or more often at the discretion of the Company to reflect the cost of additional facilities installed underground.

*7. All costs of the Company referenced in this Rider shall include the total cost of all labor and materials, applicable retirements, easements, licenses, permits, cleared right-of-way and all other incidental costs, including indirect costs. The indirect costs will include, where applicable, the cost of engineering, supervision, inspection, insurance, payments for injury and damage awards, taxes, AFUDC (Allowance for Funds Used During Construction), legal and administrative and general expenses associated with these costs. The percentage used for indirect costs reflects the Company's historical indirect cost experience. Copies of the Company's estimates of all life cycle costs, including direct and indirect costs, shall be furnished to the Customer upon request prior to construction.

8. If the Municipality repeals or rescinds its requirements concerning underground facilities subject to this Rider, the monthly charges shall continue until all costs incurred pursuant to ordinance or regulation have been paid.

9. Failure by the Municipality to pay the monthly charges shall be grounds for disconnection of service to such Customer in accordance with the Company's General Rules and Regulations Applying to Electric Service.

*Indicates Change.

RIDER EDRR
ECONOMIC DEVELOPMENT & RETENTION RIDER*

PURPOSE

The purpose of this Economic Development & Retention Rider is to encourage new industrial and commercial development in Company's service territory and to retain existing load where possible.

AVAILABILITY

Electric service under this Rider is only available, at Company's option, to customers currently served by or considering service from the Company where other viable electric supply options outside of Company's service area have been offered. Customer must be currently served, or qualify for service, under the Company's Service Schedule 3(M) Large General Service Rate, 4(M) Small Primary Service Rate, or 11(M) Large Primary Service Rate. Electric service under this Rider is only available in conjunction with local, regional, or state governmental economic development activities where incentives have been offered and accepted by customer who is requesting service to locate new or expanding facilities in the Company's service area or whose exit from the Company's service area is imminent.

APPLICABILITY

The qualifying load under this Rider shall be the entire load of a new customer, the incremental new load of an existing customer, or the portion of an existing customer's load for which exit from the Company's service area is imminent. In addition, the qualified load must meet the following criteria for consideration under this Rider:

1) The annual load factor of the customer's qualifying load is reasonably projected to equal or exceed fifty-five percent (55%) during the entire term of application of this Rider.

2) The average monthly peak demand of the customer's qualifying load is, or is reasonably projected to be, at least 500 kW during each contract year under this Rider.

3) The availability of this Rider shall be limited to industrial and commercial facilities not involved in selling or providing goods and/or services directly to the general public.

As a condition for service under this Rider, customer must furnish to Company such documentation as deemed necessary by Company to verify customer's intent to select a viable electric supply option outside of Company's service area, including an affidavit stating Customer's intent.

*Indicates Addition.

RIDER EDRR
ECONOMIC DEVELOPMENT & RETENTION RIDER(cont.)*

The Company, at its sole discretion, shall determine whether an applicant or customer meets the requirements of this Rider and the acceptability of the information provided.

Service under this Rider shall be evidenced by a contract between the customer and the Company, which shall be submitted within ten days of execution to the Commission for informational purposes. The terms of the contract shall be held in confidence by the Commission, the customer or its agent, and the Company.

INCENTIVE PROVISIONS

The Customer shall enter into a contract with the Company specifying the nature of the service to be provided, the discounts from standard tariffs to be applied, the term of the contract, and such other terms and conditions of service as are lawful and mutually agreeable. Revenues to be received from customer over the term of the contract shall be greater than the applicable incremental cost to provide electric service, as determined by the Company, ensuring a positive contribution to fixed costs. In no case shall the terms of the contract represent more than a 15% discount from otherwise applicable tariffs, before tax additions, nor shall the term of the contract extend more than five (5) years. If customer fails to fulfill the entire term of the contract, any agreed upon discounts shall become void and shall be repaid by customer.

TERM

This Rider will be limited to customers executing contracts prior to December 31, 2008, and initiating permanent service within 12 months of contract execution. Any customers under contract for this Rider prior to said date may continue to receive the benefits of the incentive provisions contained herein pursuant to the conditions set forth below. Notwithstanding the above, this Rider shall immediately become void, and the Company shall have no further obligations or liabilities hereunder, if any term or terms of this Rider are determined to be discriminatory or otherwise unlawful by a court of competent jurisdiction.

*Indicates Addition.

RIDER ERR
ECONOMIC RE-DEVELOPMENT RIDER*

PURPOSE

The purpose of this Economic Re-Development Rider is to encourage re-development of certain sites in the Company's service territory. Projects eligible for service under this Rider shall provide socio-economic benefits to the areas in which they locate as well as provide the Company with more efficient utilization of Company's existing infrastructure.

AVAILABILITY

Available, only at Company's option, to customers locating to previously vacant sites within the City of St. Louis and applying for electric service otherwise qualified for service under the Company's Service Classification 3(M) Large General Service Rate, 4(M) Small Primary Service Rate, or 11(M) Large Primary Service Rate. All Terms and Conditions of Company's tariffs shall apply to the service supplied to Customer, except as modified by this Rider.

Availability of this Rider is subject to the following limitations:

1. Project shall have an estimated average monthly peak demand of at least 500 kW during each contract year under this rider.

2. The Rider is available only for projects on sites that are within the designated areas of the City of St. Louis and defined on maps contained in this Rider.

3. This Rider is available for eligible load associated with an existing premises served or previously served by Company, provided the premises is either unoccupied or otherwise dormant (e.g. vacant land and/or buildings) for a minimum period of one hundred-eighty (180) days.

4. Electric service under this rider is only available in conjunction with Federal, State, Regional or Local governmental economic development activities such as, but not limited to, Tax Increment Financing ("TIF"), Empowerment and Enterprise Zone incentives, brownfield tax credits, new market tax credits, etc., where these incentives have been offered and accepted by customer who is requesting service to locate new or expanding facilities within the aforementioned sites.

5. Service under this Rider is limited to loads, which in the Company's sole judgment, utilize existing infrastructure in a manner which is beneficial to the local electric service delivery system.

6. This Rider is not available to a successor customer that results merely from load shifted from one location on Company's system to a qualifying site, unless approved by Company.

*Indicates Addition.

RIDER ERR
ECONOMIC RE-DEVELOPMENT RIDER (cont.)

INCENTIVE PROVISIONS

1. Facilities and Relocation Charges. - In the presence of physical conflicts associated with any new construction or expansion of customer's premises or electrical load, Company may, at its sole discretion, upon customer's request, relocate any distribution facilities to a right-of-way acceptable to Company on or off customer's premises, following the payment by customer of the Company's estimated net cost of relocating its distribution facilities. The net relocation cost chargeable to customer may be offset in part by an amount not to exceed 50 percent (50%) of any net annual revenue estimated to be derived from customer's premises, and not utilized in meeting the Company's tariff provisions governing extensions to non-residential customers.

2. Discount from Standard Tariff. - The customer shall enter into a contract with the Company specifying the character of the service to be provided and such other terms and conditions of service as are mutually agreeable. Customers meeting the criteria established in this tariff shall be eligible for a 15% discount from otherwise applicable base rate tariff charges, before application of taxes. Application of this discount provision is limited to customers whose average annual peak demand is at least 500 kW and whose annual load factor exceeds 55%. The discount shall remain in effect for up to 60 months and is not available for customers which are residential or retail in nature.

TERMS AND CONDITIONS

1. This rider will be available to customers committing to service prior to December 31, 2008 and receiving permanent service within twelve months of said committal date.

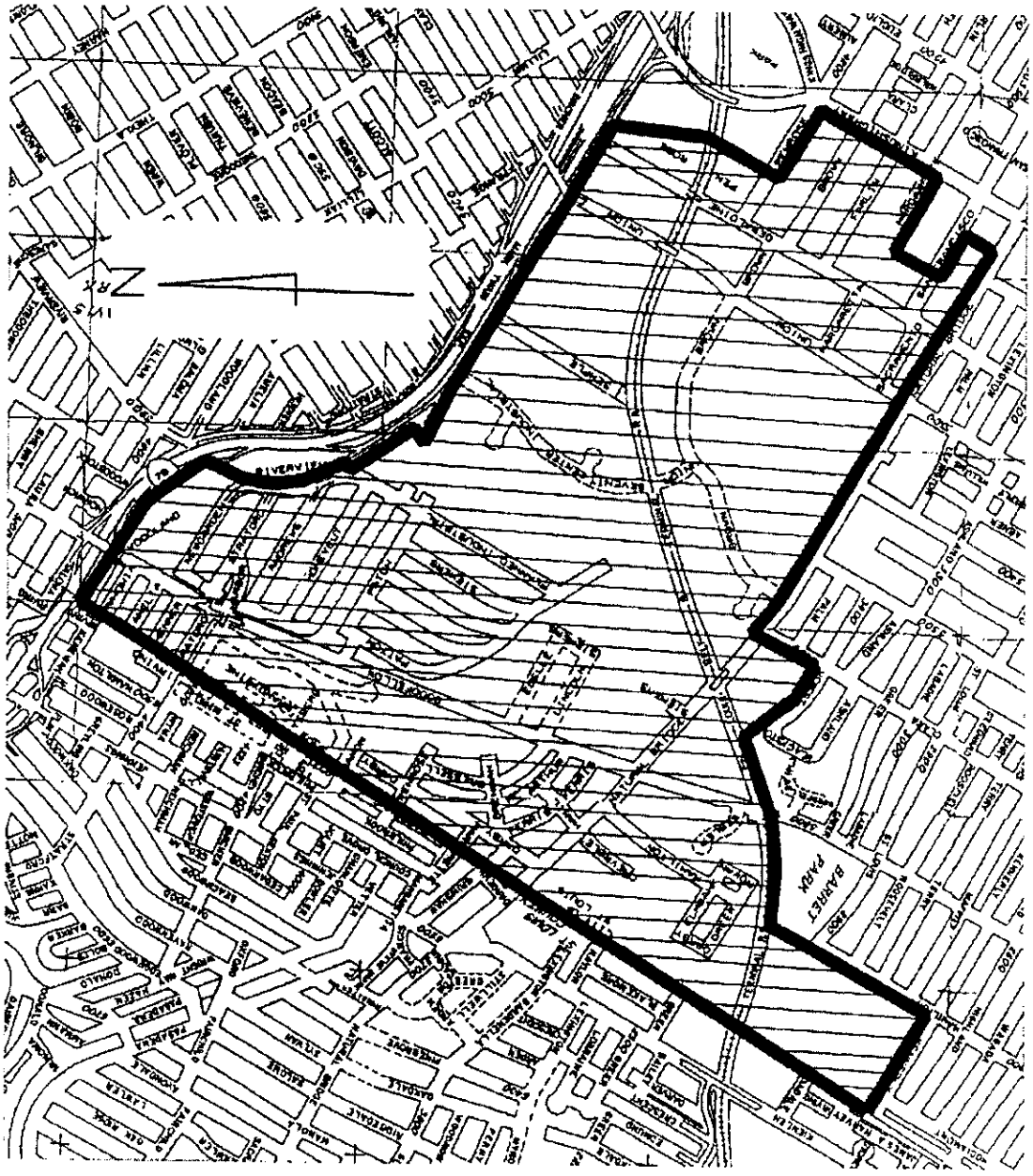
2. Customers participating in this rider will be ineligible for participation in any other economic development, economic retention, or similar tariff of the Company.

3. Maps showing the locations qualifying for consideration under this Rider, subject to Company approval, are attached and part of this Rider.

4. Notwithstanding the above, this rider shall immediately become void, and the Company shall have no further obligations or liabilities hereunder, if any term or terms of this rider are determined to be discriminatory or otherwise unlawful by a court of competent jurisdiction.

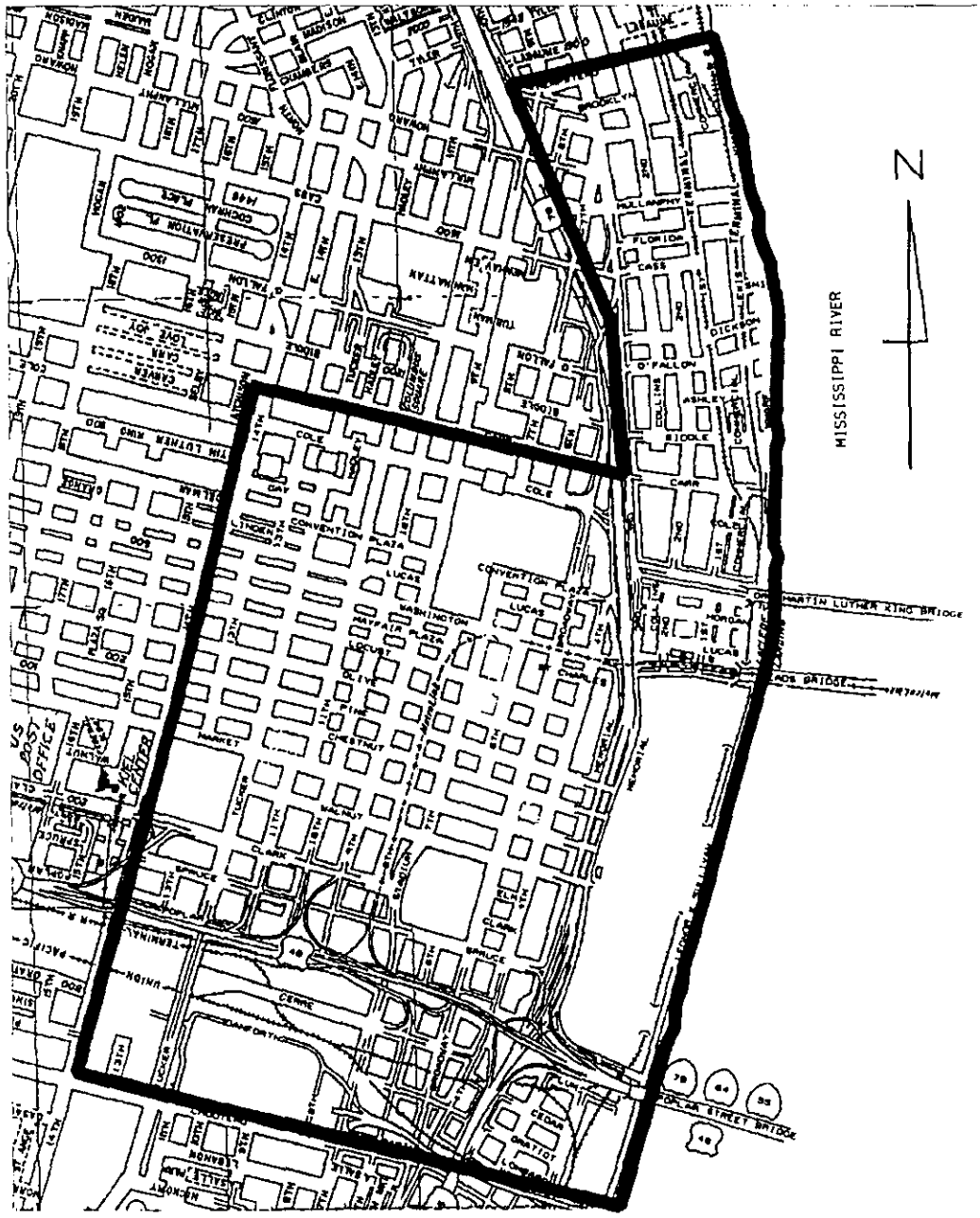
RIDER ERR
ECONOMIC RE-DEVELOPMENT RIDER (cont.)

City of St. Louis, Missouri:



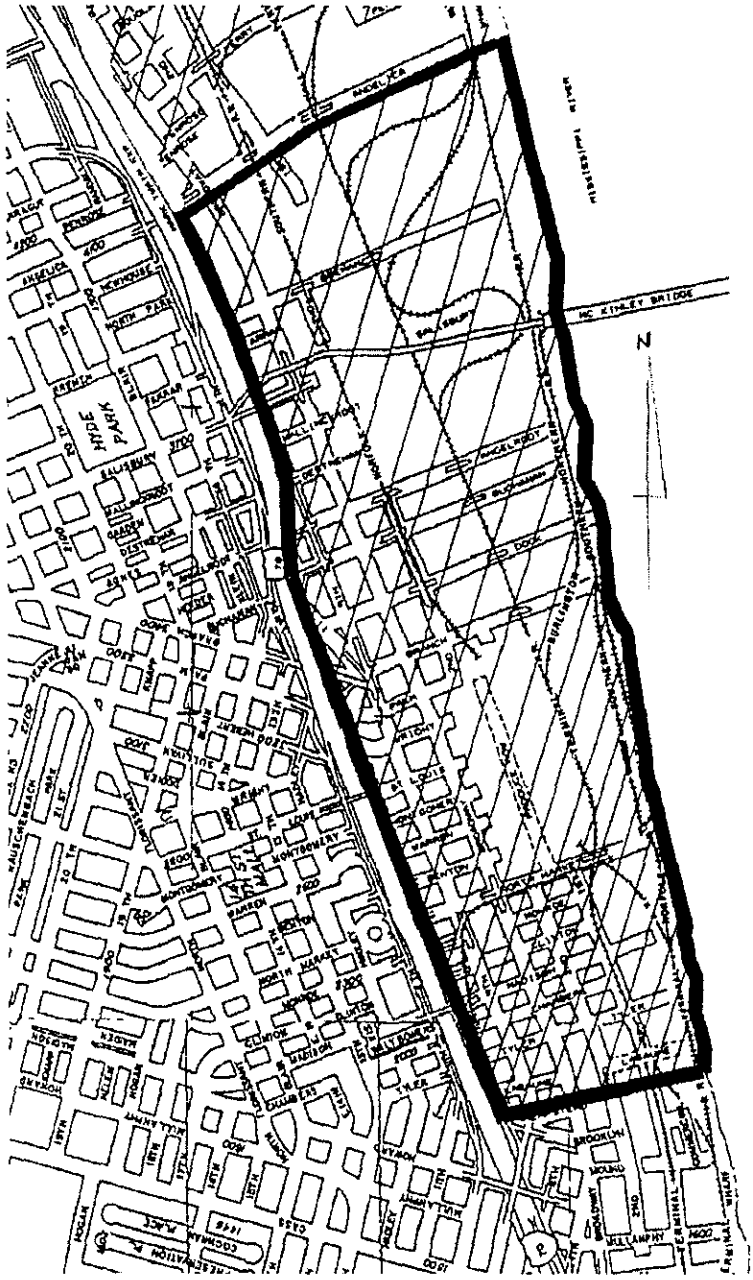
RIDER ERR
ECONOMIC RE-DEVELOPMENT RIDER (cont.)

City of St. Louis, Missouri:



RIDER ERR
ECONOMIC RE-DEVELOPMENT RIDER (cont.)

City of St. Louis, Missouri:



RIDER ERR
ECONOMIC RE-DEVELOPMENT RIDER (cont.)

City of St. Louis, Missouri:

MISSOURI ELECTRIC RULES & REGULATIONS

TABLE OF CONTENTS

*Indicates Change.

MISSOURI ELECTRIC RULES & REGULATIONS

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*Indicates Change. **Indicates Addition.

MISSOURI ELECTRIC RULES & REGULATIONS

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*Indicates Addition.

GENERAL RULES AND REGULATIONS
I. GENERAL PROVISIONS*

20. Non-Standard Service

Service at voltages, frequencies or other conditions which are no longer offered by the Company for new installations.

21. Obstruction

Obstruction of service shall include, but not be limited to, any act or instance of tampering with or bypassing the Company's meter, or any diversion of service, or any unauthorized use of or interference with the Company's provision of service situated or delivered on or about customer's premises.

*Indicates Reissue.

GENERAL RULES AND REGULATIONS
I. GENERAL PROVISIONS

*22. Power Factor

The ratio of a customer's real power requirements (kilowatts) to a customer's apparent power requirements (kilovolt amperes) or (volts X amperes)/1000.

*23. Premises

A contiguous tract of land, undivided by a public right-of-way, where all buildings and/or electric consuming devices located thereon are owned or occupied by a single customer or applicant for electric service, or where all electricity delivered thereto is utilized to supply one or more buildings and/or other electrical loads which the Company considers as components of a unified operation.

*24. Primary Service

Service provided to customer at a delivery voltage of 2,400 volts or higher.

**25. Residential

Customer whose service is furnished for domestic purposes and is eligible for Residential service pursuant to the Rate Availability section of Residential Service Rate 1(M).

*26. Revenue Taxes

Gross receipts, State sales, or other similar taxes applicable to bills rendered to customer by Company for electric service.

27. Secondary Service

Service provided to customer at a delivery voltage of 600 volts or less.

*Indicates Reissue. **Indicates Addition.

GENERAL RULES AND REGULATIONS
I. GENERAL PROVISIONS

*28. Service Facilities

Conductors, including conduit if applicable, which consist of the secondary voltage portion of the distribution system extended by Company or customer from the low voltage side of the primary/secondary voltage transformer to provide electric service to the point of delivery of the electric service, designated by Company for connection to an individual customer.

*29. Special Facilities

Facilities requested by customer, or otherwise specified by local law, which are in addition to, or to be substituted for, the standard distribution facilities which would normally be specified and provided by Company for the electrical load to be served.

*30. Subdivision

A lot, tract, or parcel of land divided into two or more lots, plots, sites, or other divisions for use for two or more new residential buildings or the land on which is constructed new residential multiple-occupancy buildings per a recorded plat thereof if such recordation is required by law.

31. Substation

Equipment at individual locations, which is designed for switching, changing or regulating the voltage of the Company's electrical supply system interconnected with the substation.

32. Tariffs

Documents filed with the Commission specifying the lawful rates and other charges, riders and rules and regulations under which the Company is required to provide service to its customers.

*Indicates Reissue.

GENERAL RULES AND REGULATIONS

I. GENERAL PROVISIONS

*33. Temporary Service

Extensions by Company for non-permanent service such as, for example, construction or seasonal operations, Christmas tree lots, carnivals, various festivals, etc., or for service to any other customer not taking and paying for such service for the minimum number of consecutive billing periods specified as the initial term in the Company's applicable tariff schedule.

*34. Termination of Service

The cessation of electric service at the request of the customer when not otherwise required by Company.

*35. Transformer

An element of the Company's transmission or distribution system whose function is to change (normally reduce) the voltage of the electric conductors to which it is connected.

*36. Transmission System

Company lines and substations, normally operating at voltages of 138,000 volts or higher, which transfer bulk electrical power from generating stations or other sources of supply to principal connection points on the Company's distribution system or to other interconnected utility systems.

*Indicates Reissue.

GENERAL RULES AND REGULATIONS
I. GENERAL PROVISIONS*

37. Voltage

The potential in an electrical system, measured in volts, normally ranging from 120 to 69,000 volts on the Company's distribution system and 138,000 volts and higher on the Company's transmission system.

C. Application for Service

Any customer requesting electric service within Company's authorized service area will provide Company with appropriate information regarding the quantity and characteristics of the anticipated electric consumption and location of the premises to be served. Appropriate personal customer identification may also be required at the request of the Company. Customer or customer's agent shall select the rate, and any applicable Riders, from the Company's currently applicable rate schedules, for which customer qualifies at that time. All electric service will be supplied subject to the provisions of the Company's tariffs applicable to the service requested and these rules and regulations, provided customer agrees to the use of the service supplied by Company for the minimum term specified in the tariff applicable to customer's electric service. Customers desiring electric service for periods less than the term specified in the applicable tariff must contract for such service under Company's Rider D.

The Company shall not be required to commence supplying service to a customer, or if commenced the Company may disconnect such service, if at the time of application such customer or any member of his household (who have both received benefit from the previous service) is indebted to the Company for the same class of service previously supplied at such premises or any other premises until payment of, or satisfactory payment arrangements for, such indebtedness shall have been made.

D. Form of Service Provided

1. Service to New Premises - Company will normally supply overhead electric service consisting of one single phase and/or one three phase secondary voltage service or one primary voltage

*Indicates Reissue.

GENERAL RULES AND REGULATIONS

III. DISTRIBUTION SYSTEM EXTENSIONS

A copy of the Company's estimated extension charges, including indirect costs, shall be furnished to the customer upon request prior to construction.

E. Overhead Extensions to Individual Residential Customers

Company will provide, at no cost, single-phase overhead electric service consisting of a meter, service drop, transformation capacity and up to 1,000 feet of additional distribution facilities, as required, no more than 500 feet of which shall be extended on private property, to the premises of an individual residential customer not located within a residential subdivision. The portion of any distribution extension applicable to customer in excess of the aforementioned allowance shall be paid for by customer, in advance of construction, at the Company's then current standard construction cost per foot of single phase overhead extensions. Alternatively, at customer's option, Company will provide any distribution facilities in addition to the meter, overhead service drop and transformation capacity referred to above, at no cost to customer provided the annual net revenue estimated to be received by Company from the extension equals or exceeds the installed cost of such additional distribution facilities, estimated at the Company's then current standard construction cost per foot of single phase overhead extensions. Where the annual net revenue estimated to be received by Company is less than the estimated extension cost applicable to customer, said cost in excess of annual net revenue shall be paid by customer to Company in advance of construction.

F. Overhead Extensions to Residential Subdivisions

* 1. Single-Family Residences

Company will provide single-phase overhead electric service consisting of meters, services, transformation capacity and all additional facilities required for the distribution of electricity, through and within the boundaries of a residential subdivision for which permanent electric service has been requested by customer/developer to two or more residential buildings, at no cost to the customer/developer, excluding subdivisions covered by the Large Lot Subdivision provisions outlined below. Company will also provide additional distribution facilities of up to 150 feet per subdivision lot, as required, to extend its existing distribution

*Indicates Change.

GENERAL RULES AND REGULATIONS
III. DISTRIBUTION SYSTEM EXTENSIONS

system to the boundaries of the subdivision site, at no cost to customer/developer. For any permanent electric distribution extension facilities to or within the subdivision, in excess of the aforementioned allowances, customer/developer shall make a deposit in advance of construction, based upon the Company's then current standard construction charges for such facilities, which deposit may be refundable in whole or in part. Semi-annually thereafter, Company will compare its standard overhead distribution cost per lot with the annual net revenue per lot estimated to be received from the additional homes within the subdivision having been connected with electric service and permanently occupied for residential dwelling purposes, after receiving notification of such connections from customer/developer. Any estimated annual net revenue per lot, from homes added during each review period, in excess of Company's standard per lot overhead costs shall be refunded, without interest, to customer/developer up to the total amount of the advance deposit actually made by customer/developer. For any home not built by the developer, any applicable refund will be made to the initial owner of each qualifying home. Such refunds will be made at semi-annual intervals from the date the deposit was received by Company, with any amounts remaining unrefunded after five years being retained by Company and credited to the Company's appropriate plant account.

* a. Large Lot Subdivisions

The above provisions regarding Overhead Extensions to Residential Subdivisions - Single Family Residences is limited to subdivisions having an average lot size of 100,000 square feet or less. Where average lot size does exceed 100,000 square feet, the Company will assess excess per lot footage charges for the amount that the average frontage footage exceeds 500 feet. In addition, for developments where the average lot size exceeds 100,000 square feet, the Company will also assess excess footage charges on individual lots for overhead services of more than a single span or underground services of more than 250 feet. Said charges will be payable in advance of construction and not be subject to refund.

2. Multiple-Occupancy Dwellings

Multiple-occupancy buildings consist of structures which stand

*Indicates Additions.

GENERAL RULES AND REGULATIONS
III. DISTRIBUTION SYSTEM EXTENSIONS

* alone, enclosed with exterior walls or are segregated from adjoining structures by fire walls, and are designed for permanent occupancy as two or more single-family residences. Extensions to subdivisions consisting of multiple-occupancy dwellings shall be made in accordance with the provisions of this paragraph F, applicable to single-family residences, utilizing an allowance of 50 feet per dwelling unit for distribution facilities beyond the subdivision boundaries, and applying a 0.60 occupancy factor to the annual net revenue estimated to be received from each multiple-occupancy dwelling unit.

G. Overhead Extensions to Non-Residential Customers

Company will provide an overhead distribution extension to individual non-residential premises at no cost to customer provided the annual net revenue estimated to be received by Company from the distribution extension equals or exceeds the estimated installed cost of the portion of required extension applicable to customer. Where the annual net revenue estimated to be received by Company is less than the estimated extension cost or, in Company's opinion, customer's revenues cannot be accurately projected, or where customer credit standing acceptable to Company cannot be established, customer or other responsible party will be required to enter into a guarantee agreement with Company, as referred to in Section III.P, herein, prior to the commencement of construction by Company.

H. Overhead Extensions to Individual Mobile Homes and Mobile Home Parks

1. Individual - Other Than Mobile Home Parks

Where a mobile home is permanently located on real property owned or leased by the mobile home occupant, utilized as a permanent dwelling unit, connected to piped water and sewage facilities, and is in excess of 400 square feet in size, Company shall extend its

*Indicates Reissue.

GENERAL RULES AND REGULATIONS
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* electrical distribution system to the mobile home service entrance equipment on the same terms and conditions indicated in this Section III for extensions to individual residential or non-residential customers, as applicable. Extensions to individual mobile homes not meeting the qualifications specified in this paragraph shall be made in accordance with the provisions of Rider D - Temporary Service.

* 2. Mobile Home Parks

Where a mobile home park owner/operator provides a designated lot with water utility and sanitary facilities for mobile homes in excess of 400 square feet in size intended for use as residential dwelling units, Company will extend its distribution system to each mobile home lot on the same terms and conditions indicated in this Section III for extensions to residential subdivisions. The billing for electric consumption at any common facilities installed within the mobile home park for the benefit of all the mobile home park occupants shall be to the park's owner/operator.

3. Recreational Vehicle Parks

Company will extend its electrical distribution system to a single delivery point to provide service to campgrounds and parks which dedicate at least 80% of their space for recreational vehicle sites. Such extensions will be made under the same terms and conditions indicated in this Section III as applicable to non-residential customers.

I. Extensions for Lighting Service

The Company's lighting tariffs are based upon the required distribution facilities being in place and no additional extension required thereof. Therefore, the cost of any extension of facilities required for lighting service shall be paid by customer to Company in advance of any construction of distribution facilities installed solely to supply electrical service for lighting.

*Indicates Reissue.

GENERAL RULES AND REGULATIONS
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J. Supplementary Distribution Extensions

* Supplementary extensions from extensions previously installed and covered under existing guarantee agreements initiated by other customers, will be made in accordance with the provisions of this Section III.J. In such instances of supplementary extensions, the guarantee amounts of the current customers served from that portion of the original extension utilized by the supplementary extension will be adjusted considering the additional revenues and facilities, if any, associated with the new customers being served. Such revised guarantee amounts will be applicable to all customers, prior and new, served from the facilities being guaranteed for the remainder of the terms of any prior guarantee agreements.

K. Underground Extensions

1. General

The Company's distribution system is generally designed and constructed as an overhead system, and electric service will normally be provided by overhead distribution extensions. Where underground distribution extensions are required by law or requested by a customer or applicant for service, underground service will be provided to a point of delivery for such service, specified by Company, under the provisions of this Section III.K. Where abnormal circumstances exist resulting in an underground extension costing less to install than an overhead extension, or Company elects to make an underground extension due to life cycle cost, engineering, construction or safety considerations, the Company's rules for overhead extensions shall apply to the estimated cost of the underground extension.

2. Individual Residential Customer Extensions

Where an underground extension is requested by an individual residential customer or required by law, Company will estimate the cost of equivalent overhead and underground extensions, and customer will pay a non-refundable contribution to Company, in advance of construction, for any excess cost of making the underground extension. The Company's rules for overhead extensions to individual residential customers shall apply to Company's estimated overhead extension costs. Customer, at his option, may install a direct

*Indicates Reissue.

GENERAL RULES AND REGULATIONS
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* buried service cable to be owned and maintained by customer, or Company will install, own, operate and maintain the service cable in customer's conduit, installed by customer in service trench in accordance with Company specifications to a delivery point designated by Company. Alternatively, the underground extension may be provided by Company in accordance with the rules herein applicable to overhead extensions, Section III.E, herein.

3. Residential Subdivision Extensions

Where an underground distribution extension for permanent electric service in a residential subdivision is requested to two or more single-family residential buildings, multiple occupancy units, or mobile homes, by an applicant/developer, or is required by law, applicant shall first satisfy the Company's applicable rules for overhead extensions to residential subdivisions, Section III.F, herein. Thereafter, applicant shall contract for and satisfy the requirements specified in this Section III.K.3. for obtaining an underground residential distribution extension.

** a. Requirements of Applicant/Developer - Applicant will initially provide, at its cost, all trenching and the installation of a complete conduit system as its contribution to the Company's underground distribution system within a residential subdivision. The conduit system installation by applicant will consist of conduit, manholes, pulling boxes, transformer pads, switchgear pads, pedestal bases and other required subsurface structures. All such materials will be provided by Company at no cost to applicant, excluding subdivisions covered by the Large Lot Subdivision provisions below. Applicants for electric service to individual single family homes shall, subsequently, provide and install service trench and service conduit. All installations will be in accordance with Company's design criteria and specifications, the National Electrical Safety Code and any other applicable codes.

b. Requirements of Company - The Company's distribution system within the subdivision will consist of all primary and secondary voltage and service cables installed by Company, including street lighting circuitry and the conduit system

*Indicates Reissue. **Indicates Change.

GENERAL RULES AND REGULATIONS
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* initially installed and contributed by applicant, except for service lateral conduit. Street light circuitry and construction temporaries, installed by Company concurrent with other primary and secondary distribution system facilities, shall be provided by Company at no charge to applicant. Thereafter, except for service lateral conduit, Company shall own, operate and maintain the entire distribution system within the subdivision, including both the portion installed by Company and that installed and contributed by applicant.

c. Options of Applicant - At the request of applicant, Company will, on a per lot or per dwelling unit basis, estimate its distribution system extension cost within the subdivision and annual net revenue, exclusive of gross receipts taxes, anticipated to be received from such homes or dwelling units connected within the subdivision. Such extension costs shall include all materials provided by Company for applicant's installation and all costs incurred by Company in the installation of its distribution system within the subdivision. Any estimated annual net revenue in excess of the subdivision extension costs specified herein may be utilized to offset any additional charges normally paid by applicant under Section III. For multiple-occupancy buildings consisting of four or more attached units, Company will, at the request of applicant, compare estimated annual net revenue per dwelling unit with the aforementioned extension costs. Company shall be limited to one comparison of such revenue and costs, for a given multiple occupancy residential subdivision, which shall be made during the first quarter of the first full calendar year following the providing of electric service to the occupants of the multiple occupancy dwelling units within the subdivision. Based upon this comparison, up to $50 of the average net revenue per dwelling unit, which exceeds the estimated extension cost per dwelling unit, shall be returned to applicant as a one-time partial refund of applicant's conduit system contribution to the Company's underground distribution system within the subdivision.

*Indicates Reissue.

GENERAL RULES AND REGULATIONS
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* d. Overhead Distribution Lines Preserved - Conversion of existing overhead distribution lines to underground shall not be required of Company. In addition, distribution lines through the subdivision shall continue to be constructed overhead unless otherwise specifically agreed to be installed underground by Company and charged to the applicant on an excess cost basis. When Company requires that an overhead line be installed on the perimeter of the development, or accepts another alternative route, for immediate or anticipated need to supply other load beyond or outside the development, or to establish distribution system ties for operating reasons through the development, Company shall be given a reasonable amount of time to construct such overhead facilities before affected lots are sold.

e. Right-of-Way and Easements - Company shall construct, own, operate and maintain the underground distribution system, within the subdivision, only on or along public streets, roads, alleys and highways which Company has the legal right to occupy, and on or along private property across which rights-of-way and easements satisfactory to Company have been received at no cost to or without condemnation by Company. Right-of-way and easements within the subdivision which are satisfactory to Company, including those which may be required for street lighting, must be furnished by applicant in reasonable time to meet Company's construction and service requirements. Prior to commencement of construction by Company, such rights-of-way and easements must be cleared of trees, tree stumps, and other obstructions, and graded level, perpendicular to the length of the easement and to within six inches of final grade by applicant, without cost to Company. If the grade is changed subsequent to construction of the distribution system in such a way as to require relocation or reconstruction of any of the underground facilities, the estimated cost of all such work required shall be paid by applicant or by its successor.

f. Joint Utility Construction - Company will endeavor to coordinate its construction work with that of applicant and other utilities whenever possible in an effort to keep the overall cost of providing the underground electric distribution

*Indicates Reissue.

GENERAL RULES AND REGULATIONS
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* system as low as possible. Company may, to any extent practicable, become a party with applicant and/or other utilities to agreements involving trenching arrangements mutually beneficial to each party and the installation of electric cables in the same trench with the cables and/or pipes of other utilities, care being taken to conform to all applicable codes and utility specifications.

* g. Designated Service Delivery Points - Feeder lines and service lines shall be installed by Company along the most practical route that will avoid known or anticipated future construction on applicant's property and permit a safe and economical installation. The normal meter location point to a single family building shall be on the side or front of the house proper, within ten (10) feet of the corner of the house proper, nearest the direction from which the service line enters the property to be served. In instances where Company and applicant agree that the extension of service to the normal meter location is impractical due to: a) rock, grade, or other soil limitations; or b) physical circumstances of the home which restrict meter accessibility for reading and testing; or c) physical circumstances of the home requiring meter installation at a height of six (6) feet six (6) inches or greater above final grade on the front of the house proper; or d) service entrance equipment to be installed in a garage, said meter location point shall be at the next nearest location designated by Company which will alleviate said impracticability while minimizing the additional length of service cable required to be installed and avoids areas of the home which may require future relocations of service lines and/or meter equipment. A meter location on the rear will only be permitted in those instances where the designated side of the house proper is not physically available for a meter attachment. A service connection at other than the above designated meter location point is not permitted unless specifically approved by Company for engineering or other reasons. Where practical, the service connection to a multiple-occupancy building of two dwelling units shall be a

*Indicates Reissue.

GENERAL RULES AND REGULATIONS
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* single service line to a two (2) meter location acceptable to Company. The service connection to a multiple-occupancy building of three (3) or more dwelling units shall be a service line or lines to a minimum grouping of meters at locations acceptable to Company.

* h. Protection of Company Facilities - Applicant shall protect the facilities of Company installed on applicant's premises and shall, unless otherwise authorized by the Company, permit no one but Company's employees or its authorized agents to handle same. In the event of loss or damage to facilities owned by Company arising out of carelessness, negligence, or misuse by applicant or its authorized agent, the cost of such loss of repairing such damages shall be borne by applicant.

i. Access by Company Employees or Agents - Applicant shall permit access to the Company's employees, or other authorized agents, for the purpose of inspecting, modifying, maintaining, or operation of Company's facilities, at all times.

j. Company Rights and Construction Standards - Company shall own, operate and maintain the conduit system initially installed and contributed by applicant, all primary and secondary underground feeder lines, underground service lines installed in customer owned conduit, and shall have the right to install pad-mounted transformers, above ground cable switching enclosures and service pedestals in the subdivision.

k. Street Lighting Facilities - Street lighting facilities installed in any subdivision shall be contracted for under the appropriate tariff of Company applicable to said installation.

l. Transition and Implementation - Developments being designed by Company and/or contracted for as of March 10, 1998 will be completed under the provisions of the Company's extension tariffs applicable and effective immediately prior to that date. Developments applied for on and after March 10, 1998 shall be supplied by Company under the provisions of Section III.K.3., herein.

*Indicates Reissue.

GENERAL RULES AND REGULATIONS
III. DISTRIBUTION SYSTEM EXTENSIONS

* m. Large Lot Subdivisions - The above provisions regarding Residential Subdivision Extensions - Requirements of Applicant/Developer is limited to subdivions having an average lot size of 100,000 square feet or less. Where average lot size does exceed 100,000 square feet, the Company will assess excess per lot footage charges for the amount that the average frontage footage exceeds 500 feet. In addition, for developments where the average lot size exeeds 100,000 square feet, the Company will also assess excess footage charges on individual lots for overhead services of more than a single span or underground services of more than 250 feet. Said charges will be payable in advance of construction and not be subject to refund.

4. Non-Residential Extensions

** a. Application

Where an underground extension is requested by a non-residential customer or required by law, Company will first estimate the cost of equivalent overhead extension and the Company's rules for overhead extensions to individual non-residential customers, Section III.G, shall apply. The underground distribution facilities will be provided at Company's sole discretion following the payment by customer of the Company's estimated excess cost of the underground extension over the cost of an equivalent overhead extension. Where such annual net seasonal rate revenue is less than the excess underground extension, if any.

b. Point of Delivery of Service

Company will designate to customer the point of delivery of the required electric service and customer shall be responsible for the installation, maintenance, replacement, enlargement or relocation of all underground electric service facilities, other than metering, to the Company's designated delivery point.

*Indicates Addition. **Indicates Change.

GENERAL RULES AND REGULATIONS

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* c. Specifications

Customer will install, maintain, replace, enlarge, or relocate all underground conduit, foundations, manholes, service boxes, transformer pads, switchgear pads, and other surface and sub-surface structures to meet Company specifications which are necessary to contain and/or support Company's electrical primary and secondary cables and equipment within the boundaries of the development. Maintenance, replacement, enlargement, or relocation of such facilities will be done by the Company at the customer's expense once they contain or support energized cables or equipment. Company will provide standard switchgear pads and transformer pads to customer for installation in order to maintain uniformity and quality control of these items. Customer is to provide Company open access to said facilities, and when necessary, remove obstructions, improvements, decorative structures, etc., when Company requires such access for maintenance, replacement, enlargement, etc. When Company requests additional conduits or larger structures for facilities that will serve customers beyond the boundaries of the development, Company will pay the incremental or extra cost of those additional facilities.

L. Extensions Requested in Advance of Permanent Service

Where customer requests Company to complete all or a portion of an extension in advance of when said installation is required to provide permanent electric service, and Company agrees to do so, customer shall pay for such advancement of facilities at the monthly rate of 2.0% of the estimated installed cost of the extension being advanced. Such payments shall be non-refundable and shall continue until the permanent metering for the premises is installed by Company and utilized to provide permanent service thereto.

*Indicates Reissue.

GENERAL RULES AND REGULATIONS

III. DISTRIBUTION SYSTEM EXTENSIONS

* M. Modification or Enlargement of Distribution System

Modifications or enlargements of Company's distribution system associated with additional electrical load of existing customers shall be performed at no cost to customer provided the estimated additional annual net revenue to be received equals or exceeds the estimated cost of the distribution system modifications or enlargements. Where the estimated additional annual revenue to be received is less than Company's estimated modification or enlargement costs, or such revenue cannot be accurately projected, or customer credit standing acceptable to Company cannot be established, customer or responsible party will be required to enter into a guarantee agreement, as provided in Section III.P prior to the commencement of construction by Company. Additional annual net revenue, referred to herein, excludes customer's existing net revenue during the twelve months immediately preceding the extension modification from the guarantee agreement calculations.

Where modifications or enlargements of Company's distribution system are performed at the request of any existing customer and no additional revenue is anticipated therefrom, customer shall pay, in advance, the total estimated costs associated with such changes.

N. Relocation of the Distribution System

Company may, at its sole discretion, upon customer's request, relocate any distribution facilities providing service to customer and/or other parties to a right-of-way acceptable to Company, on or off customer's premises, following the payment by customer of the Company's total estimated cost of said relocation.

** In the presence of physical conflicts associated with any new construction or enlargement of customer's premises or electrical load, Company may, at its sole discretion, upon customer's request, relocate any distribution facilities to a right-of-way acceptable to Company on or off customer's premises, following the payment by customer of the Company's estimated net cost of relocating its distribution facilities. The net cost of relocation referred to herein excludes any costs estimated by Company to be associated with the supply of any additional electrical requirements of customer, absent the relocation of any distribution facilities. The net relocation cost chargeable to customer may be refundable in whole or in

*Indicates Reissue. **Indicates Change.

GENERAL RULES AND REGULATIONS
III. DISTRIBUTION SYSTEM EXTENSIONS

part under the advance deposit provisions applicable to residential extensions.

* When Company agrees to relocate existing overhead facilities with an underground installation, the customer will be responsible for all costs associated with the undergrounding of facilities including spare conduits, manholes, and other structures or equipment required to replace the to-be-vacated overhead right-of-way considering present and future needs as determined by Company.

O. Advance Refundable Deposits

Advance refundable deposits may be required from customer or other responsible party for all or a portion of Company's distribution extensions, as specified in Section III of these rules and regulations. Such advance deposits will be paid to Company prior to the commencement of construction of the extension by Company. Advance refundable deposits provided to Company which subsequently qualify for refund, in whole or in part, will be refunded to depositor on a pro rata basis, without interest, following notification by depositor and Company verification of the size, type and number of customers connected and taking permanent electric service within the tract of land for which the refundable deposit was made. Such refunds will be made at semi-annual intervals from the date the deposit was received by the Company, with any amounts remaining unrefunded after five years being retained by Company and credited to the Company's appropriate plant account. A guarantee agreement, as provided in Section III.P, may also be required by Company, at its sole discretion, for any portion of a line extension covered by an advance refundable deposit.

P. Guarantee Agreements

A written guarantee agreement between Company and customer or other responsible party will be required for any extension where the estimated cost thereof exceeds the estimated net annual revenue estimated to be received by Company from said extension or, in Company's opinion, customer's revenues cannot be accurately projected, or customer credit standing acceptable to Company cannot be established. Said guarantee will be applicable to the total cost of the extension chargeable to customer, with the required guarantee agreement being entered into by the customer and the Company prior to the commencement of construction by Company.

*Indicates Reissue.

GENERAL RULES AND REGULATIONS

III. DISTRIBUTION SYSTEM EXTENSIONS

*Company may, at its sole discretion, require an advance deposit of all or any portion of such guarantee amount to insure that the revenue estimated to be derived from the extension will in fact be realized. The guarantee agreement will provide for the following:

* 1. The monthly guarantee payment to be made by customer will be a minimum of one twelfth (1/12) of the total cost of the extension being guaranteed. Such guarantee payment will be exclusive of any revenue taxes applicable to customer's total bill for service and shall commence with the customer's fourth billing for permanent service being provided by the extension being guaranteed.

2. Deficiency revenue is defined as that portion of any monthly guarantee payment which exceeds the net revenue from permanent service to customer.

3. A guarantee will terminate within the 12-month guarantee period whenever the total net revenue realized from the permanent service provided to the premises served by the extension equals or exceeds the total cost of the extension.

4. Whenever the total net revenue from permanent service to the premises served by the extension and the accumulated deficiency billed to customer equals or exceeds the total cost of the extension at any time during the 12-month guarantee period, the customer has satisfied the guarantee agreement. The Company will apply any accumulated deficiency payments in excess of that necessary to satisfy the above toward the subsequent purchase of electric service, exclusive of revenue taxes, by customer during the remainder of the guarantee period. No interest shall be applied to any deficiency payments so applied.

** In situations where Company is in direct competition with a Coop, Municipality, or other similar energy provider, Company may offer an amended form of the Guarantee Agreement which recovers any anticipated deficiency amounts over a term of three years instead of one year.

*Indicates Reissue. **Indicates Addition.

GENERAL RULES AND REGULATIONS
III. DISTRIBUTION SYSTEM EXTENSIONS

Q. Special Facilities

* 1. General

Where customer requests and Company agrees to install distribution facilities not normally contemplated for installation, or otherwise provided for, under Company's standard rate schedules, Company may at its option provide such facilities under the provisions of this section. Examples of facilities which fall into this category of "special" include, but are not limited to, duplicate or additional service facilities, excess transformer capacity or other distribution facilities, and facilities necessitated by special legal or engineering requirements.

2. Payments by Customer

Where Company agrees to supply distribution facilities under the provisions of this paragraph Q in lieu of other alternatives available to customer, customer shall pay to Company a one-time contribution equal to the total additional costs incurred by Company in supplying such facilities. Customer shall also pay to Company an additional one-time contribution equal to ninety percent of such total additional costs for the present value of the Company's projected operations, maintenance and subsequent replacement cost of such facilities, which shall be continuously owned and maintained by Company. All charges payable to Company shall be non-refundable and due in advance of construction. Such payments by customer shall be in addition to any payments required for electric facilities provided under the Company's standard line extension rules or other tariff charges.

3. Supply and Billing Standards

Company will designate the point of delivery of electric service relative to the installation of any additional facilities provided to customer hereunder and the service supplied through such facilities installed on and after May 5, 1990 will not be cumulated or otherwise combined, for billing purposes, with any other service supplied to customer. When total or partial replacement of any special facility installation is required, such revision will be made by Company at no cost to customer. Any enlargement of such

*Indicates Reissue.

GENERAL RULES AND REGULATIONS
III. DISTRIBUTION SYSTEM EXTENSIONS

* previously installed facilities requested by customer shall be made in accordance with Company's standard line extension rules. Following any such replacement, or enlargement, all separately installed special facility connections shall be billed as provided herein without application of monthly special facility charges, and maintained by Company in the same manner as Company's standard line extension facilities serving other customers.

* 4. Installations Prior to November 2, 1983

Customers utilizing facilities installed hereunder prior to November 2, 1983 had the option of paying Company for such facilities a) as a one-time contribution of the total installed cost of such facilities, or b) at the monthly rate of 2.00% of such total installed cost. These options are limited to those customers currently utilizing existing special facilities installed prior to November 2, 1983. The present charges and form of billing applicable to all special facility connections referred to herein shall continue until any total or partial replacement or enlargement of such facility is required. Thereafter, such revisions will be made by Company and the subsequent metering and billing of all service provided over such newly installed facilities standardized, as provided in paragraph Q.3. herein.

5. Installations Between November 2, 1983 and July 23, 1992

Customers utilizing facilities installed hereunder between November 2, 1983 and May 5, 1990, had the option of paying Company a one-time contribution of the total installed cost of such facilities, plus a monthly charge of 0.75% of the installed cost of such facilities for the operation, maintenance and subsequent replacement of such facilities. For installations between May 5, 1990 and July 23, 1992, customers paid Company a one-time contribution of the total installed cost of such facilities, with the application of the latter 0.75% monthly charge limited to those installations costing in excess of $10,000. The present charges and form of billing applicable to all special facility connections referred to herein shall continue until any total or partial replacement or enlargement of such facility is required. Thereafter, such revisions will be made by Company and the subsequent metering and billing of all service provided over such newly installed facilities standardized, as provided in paragraph Q.3. herein.

*Indicates Reissue.

GENERAL RULES AND REGULATIONS
IV. MEASUREMENT OF SERVICE

d.	Any special meter or meter equipment, such as primary and switchboard type meters	@ 2.00% per month of the cost of such meter or equipment

* C. Multiple Metered Account Billing

Where more than one meter is installed for metering the premises of an individual account in accordance with paragraphs A and B above, the sum of each watthour meter's kilowatthour usage and each demand meter's individual maximum non-simultaneous kilowatt demand will be used for billing purposes. Under all circumstances involving multiple metered accounts, any alternating current watthour meter registering zero usage in a given billing month shall be subject to the monthly charge for three phase meters, specified in paragraph B of this Section IV, during each month of zero usage.

D. Meter Inspections and Testing

Company's meters shall be inspected and tested for accuracy in accordance with applicable Missouri Public Service Commission Rules. If customer requests a meter test within 12 months of any previous testing of such meter, a standard charge based on meter type will be assessed for meters found to have an average meter error of 2 percent or less.

*Indicates Change.

GENERAL RULES AND REGULATIONS

IV. MEASUREMENT OF SERVICE

E. Limited Unmetered Service

Where service is required for electrical loads which are constant over a predetermined operating schedule and can be reasonably estimated by Company, Company may at its sole discretion waive the metering requirement for the limited types of load referred to herein. In such instances Company would calculate the amount of service to be charged under its applicable rate schedule. Service supplied under the provisions of this paragraph are limited to lighting and CATV power booster loads of 5 kVA or less at any one service delivery point.

*F. Multiple Occupancy Building Metering

1. Each Residential and commercial unit in a multiple-occupancy building construction of which has begun after June 1, 1981 shall have installed a separate electric meter for each Residential or commercial unit.
2. Each mobile home unit in a mobile home park, construction of which has begun after June 1, 1981 shall have installed a separate electric meter for each mobile home unit.
3. For the purposes of carrying out the provisions of sections (1) and (2), the following exceptions apply and separate metering and billing of electricity shall not be required for the following:
   a. For transient multiple-occupancy buildings and transient mobile home parks - for example, hotels, motels, dormitories, rooming houses, hospitals, nursing homes, fraternities, sororities, campgrounds and mobile home parks which set aside, on a permanent basis, at least eighty percent (80%) of their mobile home pads or comparable space for use by travel trailers;
   b. Where commercial unit space is subject to alteration with change in tenants as evidenced by temporary versus permanent type of wall construction separating the commercial unit space for example, space at a trade fair;
   c. For commercial adjacent buildings;

*Indicates Addition.

GENERAL RULES AND REGULATIONS
IV. MEASUREMENT OF SERVICE *

d. For that portion of electricity used in central space heating, central hot water heating, central ventilating and central air-conditioning systems;

e. For buildings or mobile home parks where alternative renewable energy resources are utilized in connection with central space heating, central hot water heating, central ventilating and central air-conditioning systems; or

f. For all portions of electricity in commercial units in buildings with central space heating, ventilating and air-conditioning systems.

g. Residential units that do not have kitchen and bathroom facilities separate from common use facilities.

h. Portions of buildings in which separate metering is impractical, such as concession stands in lobbies, and individual offices that share office service areas.

i. Multiple-unit buildings that are designated as congregate, assisted-living care facilities for elderly or handicapped persons.

j. Multiple-unit buildings which do not meet the individual metering requirements of the Public Utility Regulatory policies Act of 1978 (PURPA) Chapter 16 U.S.C.& 2625(d). stated below:

"Master Metering"

Separate metering shall be determined appropriate for any new building for purposes of section 2623(b)(1) of this title if -

(1) There is more than one unit in such building

(2) The occupant of each such unit has control over a portion of the electric energy used in such unit, and

(3) With respect to such portion of electric energy used in such unit, the long-run benefits to the electric consumers in such building exceed the costs of purchasing and installing separate meters in such building"

*Indicates Addition.

GENERAL RULES AND REGULATIONS
V. BILLING PRACTICES

b. In the event of an undercharge, an adjustment shall be made for the entire period that the undercharge can be shown to have existed not to exceed twelve (12) monthly billing periods calculated from the date of discovery inquiry or actual notification of the Company, whichever was first;

c. Where, upon test, an error in measurement is found to be within the limits prescribed by Commission rules, no billing adjustment will be made;

d. When evidence of obstruction is found, or there are misrepresentations of the use of service by the customer, the Company will calculate the billing adjustment period in accordance with the applicable statute of limitations for the prosecution of such claim after determining the probable period during which such condition existed from all related and available information; and

e. In any event, no billing adjustment will be made where the full amount of the adjustment is less than one dollar ($1) and no interest shall be paid or collected on any billing adjustment provided for herein.

* 2. Non-Residential - For all non-residential billing errors, the Company will determine from all related and available information the probable period during which the error condition existed and shall make billing adjustments for the estimated period involved as follows:

a. No billing adjustment will be made where the dollar amount of the adjustment is less than $15.00. No interest shall be paid or collected on any billing adjustment provided for herein.

b. Where upon test an average meter error is found to be greater than 2 percent a billing adjustment will be made to compensate customer where the meter reads fast, and to compensate Company where the meter reads slow. However,

*Indicates Change.

GENERAL RULES AND REGULATIONS

V. BILLING PRACTICES

* any such billing adjustment will be applicable only for the probable period during which the meter error existed and shall be limited to the twenty-four (24) billing periods preceding the one in which the error was determined plus the elapsed period in the current billing period during which the test was made.

* c. Where a non-registering meter is found, Company will determine from all related and available facts the probable period during which such inaccuracy existed and render adjusted bills for the period involved, provided, however, that such period shall not exceed the preceding six (6) billing periods plus the elapsed time in the current billing period during which each inaccuracy was determined.

* d. Bills rendered which are based on incorrect registrations due to improper meter connections, the application of an improper meter constant, improper application of any rate schedule not selected by customer, or similar reasons, shall be subject to adjustment for the current and twenty-four (24) prior billing periods, as can be substantiated by Company records.

** e. "Average meter error" shall be determined in accordance with provisions set forth in rules of the Missouri Public Service Commission.

*** f. No corrections to metering data for meter error shall extend beyond the in-service date of the meter discovered to be in error, nor shall any correction be required to extend beyond the date upon which the current customer first occupied the premises at which the error is discovered.

H. Change of Rate

1. The rate selected by customer and specified by contract for service (if a written contract is required) shall be applied to customer's account for a period of not less than one year

*Indicates Change. **Indicates Reissue. ***Indicates Addition.

GENERAL RULES AND REGULATIONS
V. BILLING PRACTICES

* unless customer elects to transfer to a different rate during the first ninety (90) days of service. If so elected, the new rate shall be applied retroactively to the commencement date of customer's service.

2. Upon completion of the initial term of use of service under any rate, customer may select any other applicable rate and the rate so selected shall apply for a period of not less than that specified in the term of use of such selected rate.

3. Selection of rate shall be the obligation of the customer. A new rate when selected under and subject to the provisions set forth above will be placed in effect in the billing period following receipt of customer's request therefore.

4. Where a customer's load is abnormally affected during temporary periods of construction, alteration, preliminary or experimental operations, fire, or acts of God, Company may, upon prior agreement with customer, adjust or modify its billing or other charges otherwise applicable during the current or succeeding months in consideration of the particular circumstances in each such case.

5. Where abnormal and significant reductions in customer's operations occur due to events such as production curtailments, plant alternation, labor stoppages, fires or other acts of God, etc. which reduce customer's monthly billing demand below 100 kilowatts, customer may transfer to the Small General Service Rate for all billing periods subsequent to the initial billing period under such abnormal operation, following Company's receipt of written request for such change from customer. During such billing periods under the Small General Service Rate, any billing discounts under Riders B and C shall not apply.

6. Customers will not be permitted to evade the intent of the provisions of this paragraph H by temporarily terminating service.

*Indicates Reissue.

GENERAL RULES AND REGULATIONS

V. BILLING PRACTICES

L. Rent Inclusion

* The furnishing of electric service by a customer to a third party as an unidentifiable rental component, without such service being segregated and billed to the third party by Company, is generally prohibited by the Commission's rules. Separate metering shall be required for each unit in multiple occupancy buildings constructed after June 1, 1981, except for the electrical usage as set forth under Measurement of Service Section IV. F.

Any person or entity affected by the provisions of this Section V.L. Rent Inclusion may file an application with the Commission seeking a variance from all or parts of such provisions for good cause shown, pursuant to the Commission's rules applicable thereto.

Nursing homes, as referenced in (1.) above, shall include all facilities licensed by the State of Missouri Department of Social Services Division of Aging. Central space heating, water heating and air conditioning systems referred to in (4.) above shall include those systems employing individual heating/cooling interconnected with centralized heating/cooling sources by means of a central piping system containing water or other fluids suitable for such purposes.

**M. Resale of Service

The furnishing of metered electric service by a customer of Company to a third party for a specific identifiable charge based upon such metered consumption is prohibited except where such practice originated prior to July 24, 1958. Where such practice has continued since July 24, 1958, the charge for electric service from customer to a third party shall not exceed the charge which would result from the application of Company's appropriate rate, contained herein, for comparable electric service. For such exceptions, the practice of resale shall be discontinued when such premises are remodeled, rebuilt or replaced.

*Indicates Change. **Indicates Reissue.

GENERAL RULES AND REGULATIONS
V. BILLING PRACTICES

N. Partial Payments

If a partial payment is made on a billing including only current charges, the Company shall first credit the payment to the balance outstanding for utility charges before crediting a deposit. If a partial payment is made on a billing which includes a previous balance, the Company will credit the payment first to previous utility charges, then to previous deposit requirements before applying any payment to current charges. No portion of any payment will be applied to special charges until all utility charges are paid in full and all required deposits have been made. (This section reflects a variance from Rule 4 CSR 240-13.020(11) granted by the Commission in Case No. EO-98-263.)

* O. Seasonal Service Disconnects

When a Customer served under this schedule makes only seasonal use of electric service and requests the Company to:

1. Disconnect the service, and where said service is left disconnected for fewer than 12 months, Customer shall pay to the Company at the time of reconnection an amount equal to the applicable monthly minimum charges times the number of months service was disconnected, plus a service reconnection charge.

2. Disconnect the service and remove Company facilities, Customer shall pay to the Company at the time of reconnection the total cost to the Company of installing and removing said facilities, less salvage, if any.

*Indicates Addition.

INDUSTRIAL DEMAND RESPONSE PILOT

PURPOSE

The purpose of this pilot is to evaluate the viability of demand response opportunities within the industrial community. Program participants shall have demand side alternatives reducing their reliance on supply side resources for all or a portion of their load. The pilot program will facilitate short term reductions in system load to address system reliability and other system operating conditions.

AVAILABILITY

This pilot is available to any industrial customer receiving service under Service Classification No.11 (M)("Eligible Tariff"), has a minimum billing demand of 25,000 kW, has a minimum curtailable load of 5,000 kW, has a minimum annual load factor of 65%, remains on such tariffs and is willing to enter into a written contract for a period of one (1) year with the Company in accordance with this pilot. However, in no event shall the number of customers participating in this pilot exceed five (5) nor the aggregate curtailable loads exceed 100,000 kW. All electric service utilized at the customer's premises, with the exception of any separately contracted for street and outdoor area lighting service, must be served under the contract provisions of this pilot.

Customers receiving service under the following riders are not eligible for service under this pilot:

a) Rider L - Voluntary Curtailment Rider
b) Rider M - Option Based Curtailment Rider
c) Rider EDR - Economic Development Rider
d) Rider EDRR - Economic Development and Retention Rider
e) Rider ERR - Economic Re-development Rider
f) Rider F - Annual Recurring Service

A customer taking service under any non-eligible tariff may not transfer to an eligible tariff for purposes of taking service under this pilot, unless such customer has been on its current tariff for at least a twelve-month consecutive period or otherwise satisfied all of its obligations under its existing tariff or contract.

Customers taking service under the standard provisions of Rider EDR, EDRR or ERR may become eligible for service under this pilot by first terminating service under those Riders. However, such customers are subject to the same requirement in the previous paragraph regarding transfers to another eligible tariff.

Service under this pilot shall be contingent on customer executing a Contract with Company specifying the initial amount of Firm Power Requirement and anticipated Interruptible Power Level.

INDUSTRIAL DEMAND RESPONSE PILOT (cont.)

CUSTOMER LOAD CURTAILMENT PROVISIONS

Interruptible Power may be curtailed at the Company's sole discretion whenever one or more of the following conditions exist:

a. It is anticipated that Company will set an annual system peak,
b. Load Reductions will positively impact Transmission System constraints,
c. Load Reductions are required to maintain a firm supply to Company's non-interruptible customers,
d. Load Reductions will avoid external purchases of high cost energy,
e. Other conditions exist which may be eased by a reduction in system load.

Curtailments on Customer's Interruptible Load will be subject to the following constraints:

a. Company will attempt to provide customer with up to two hours advance notice of any interruption or curtailment. Such notices shall be no shorter than the lesser of 30 minutes or any such time specified in a directive from MISO or the applicable Balancing Authority in their operation of such load curtailment tariffs. No other obligation exists under this tariff to provide such advance notice of any interruption or curtailment nor any assumption of any liability for failure to do so.
b. No single Interruption Event shall continue for more than 48 hours consecutively.
c. The total duration for all curtailment events called during the annual contract period (June 1 - May 31) shall not exceed 200 hours for each participant. The Company retains all rights to interrupt or curtail customer's load beyond the 200 hours cap whenever it is determined that an interruption is necessary due to system operating conditions making it undesirable to continue service for reasons of reliability, system security, or other emergency as determined by the Company.
d. Company may elect to curtail only a portion of the customers enrolled in this pilot for any given event.

BUY THROUGH ENERGY OPTION

Company may, at its sole discretion, make available to customers called to curtail interruptible power, a buy-through option for a portion of or the total amount of the customer's curtailable load. When available, buy-through power must be arranged in advance of the curtailment start time and will be priced at 110% of the MISO hourly market clearing price. Such market clearing energy price is defined

INDUSTRIAL DEMAND RESPONSE PILOT (cont.)

as the hourly MISO locational marginal price (LMPs) including MISO losses, congestion costs and shall represent a full pass-through of all costs incurred by the Company to provide buy-through service to each Customer at the load zone recognized by MISO as encompassing the load of the Company.

Failure of a customer to reduce their load to the current Firm Power Level, unless covered by pre-arranged buy-through provisions, will result in the Firm Power Level for the current and all succeeding months being adjusted to the maximum hourly demand during such curtailment periods.

BILL CREDITS

Demand Credit:

Customer shall receive a credit of $2.00 per kW of monthly curtailable demand for each billing month. The monthly curtailable kW will be calculated each month as the current months billing demand (as defined in Schedule No. 11(M) Large Primary Service, less the customer's current Firm Power Level.

Energy Credit:

Customer shall receive an energy credit of $.0800/kWhr for each kWhr of load reduction below the customer's Average Load Level for each hour during the curtailment period. The customer's Average Load Level will be calculated for each contract period of June 1 through May 31 as the total kWhr usage of the customer during the 12 months immediately preceding the contract period divided by 8760(8784 for leap year). The Average Load Level may be adjusted by Company to reflect any significant seasonal differences or material changes to customer's operations since the historical determination period. No Energy Credit shall be applicable to any amount of energy purchased pursuant to the buy-through energy provisions of this tariff.

TERM OF CONTRACT AND TERMINATION

Customer shall sign a contract for an initial term of one (1) year with the term commencing on the June 1 following the contract execution date. Prior to the start of any subsequent annual term, the customer's continued qualification for the pilot will be reviewed and the Customer's Average Load Level for the next contract period determined. If it is anticipated that customer will continue to qualify for service under this pilot for the next contract period, the contract will be automatically renewed for a successive term of one (1) year, subject to termination at the option of the Company or customer by giving thirty (30) days notice prior to the start of the next contract period. In no event will service under this pilot continue after May 31, 2009.

INDUSTRIAL DEMAND RESPONSE PILOT (cont.)

LIMITED APPLICATION

This pilot will no longer be in effect after May 31, 2009

TERMS AND CONDITIONS

Service hereunder is subject to the "Missouri Electric Rules and Regulations" on file with the Missouri Public Service Commission and "Tax Adjustment" under the otherwise applicable rate schedule. In the event that MISO determines that this pilot does not qualify as an interruptible load program, AmerenUE reserves the right to terminate this program and will work together with participants to reach mutual agreement on a revised pilot that meets MISO criteria.

PILOT PROGRAM EVALUATION

The Company shall perform an evaluation of the pilot program which includes evaluation of the benefits of the pilot. The evaluation will document the level of participation in the pilot and any problems that the Company experienced in implementing the pilot. The pilot evaluation shall be submitted to the Commission Staff, Office of the Public Counsel, and participating customers (or their representatives) no later than 6 months after the conclusion of this pilot program.

VOLUNTARY GREEN PROGRAM

PURPOSE

The purpose of this Voluntary Green Program tariff is to provide customers with an option to contribute to the further development of renewable energy technologies. All references to 'green' in this tariff shall mean renewable energy certificates ("RECs"). One REC is the equivalent of 1,000 kWh produced from a qualified renewable energy source and represents the positive environmental attributes of electricity generated by renewable energy sources such as: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops and other renewable resources deemed to be Green-e Certified by the Center for Resource Solution's Green-e Standard. Customers participating under this program will not directly receive any renewable energy commodity or product as a result of their participation. Rather, when a customer signs up for the Voluntary Green Program, Company shall purchase Green-e Certified RECs equal to 100% of the electricity consumption of a residential or small general service customer. All other non-residential customers can purchase blocks of RECs in increments equal to 1,000 kilowatt hours (kWh) of electricity use.

AVAILABILITY

This tariff is available to and may be used in conjunction with the Company's Electric Service Classifications 1 (M) Residential Service Rate, 2 (M) Small General Service Rate, 3 (M) Large General Service Rate, 4 (M) Small Primary Service Rate, 11 (M) Large Primary Service Rate, 12 (M) Large Transmission Service Rate, 5 (M) and 6 (M) Street and Outdoor Area Lighting Rates, 7 (M) Municipal Street Lighting Rate, or 8 (M) Private Ornamental Street Lighting Rate.

APPLICABILITY

The applicability of this tariff is limited to customers receiving service under the above referenced Service Classifications and who voluntarily agree to participate in this program pursuant to the provisions herein.

MONTHLY CHARGES

Service Classification No 1 (M), 2 (M): 1.50 cents per kWh (1)
Service Classification Nos. 3(M), 4 (M), 5 (M), 6 (M), 7 (M), 8 (M), 11 (M), and 12 (M): $15.00 per 1,000 kWh block (2)

(1) Actual monthly charge shall be the result of Customer's metered kWh usage at the designated price.

(2) Minimum of 1 block, regardless of usage. Actual number of blocks will be subject to agreement between Company and Customer and not necessarily tied to monthly kWh usage.

VOLUNTARY GREEN PROGRAM (cont.)

COMPANY OBLIGATIONS

The Company will purchase RECs from its contractual partner, 3 Phases Energy, its successor, or assignee, in sufficient quantities to match the units billed under this tariff. Title to the RECs will rest with the Company and the Company will in turn retire such RECs on behalf of the customers participating in the program. Additionally, the Company's Voluntary Green Program will be Green-e Certified ® by the nonprofit Center for Resource Solutions.

TERMS AND CONDITIONS

Charges for participation under this tariff shall be added to Customer billings from Company for electric service. Customers will be able to withdraw or cancel participation in this program at any time by notifying the company. In addition, under no circumstances will the Company's late pay charge or disconnection of service provisions as they relate to charges under this tariff be applied or implemented.

TAX ADJUSTMENT

Any license, franchise, gross receipts, occupation or similar charge or tax levied by any taxing authority on the amounts billed hereunder will be added to bills rendered to customers under the jurisdiction of the taxing authority.

AmerenUE
CASE NO. ER-2007-
PROPOSED CLASS REVENUE REQUIREMENTS
($000's)

Customer Class	Current Base Revenue	Proposed Base Revenue	Required Revenue Adjustment	% Change
Residential	$ 850,202	$ 935,272	$ 85,070	10.0%
Small General Service	$ 226,708	$ 280,708	$ 54,000	23.8%
Large General Service	$ 418,263	$ 503,057	$ 84,794	20.3%
Small Primary Service	$ 182,438	$ 225,681	$ 43,243	23.7%
Large Primary Service	$ 155,950	$ 223,299	$ 67,349	43.2%
Large Transmission Service	$ 137,208	$ 163,437	$ 26,229	19.1%
Total	$ 1,970,769	$ 2,331,454	$ 360,685 (1)	18.3%

(1) - Targeted increase from AmerenUE witness Mr. Gary S. Weiss testimony is $360,708; however, rate rounding resulted in a shortfall of approximately $23K.

MISSOURI
RESIDENTIAL SERVICE CLASSIFICATION NO. 1(M)
TYPICAL MONTHLY BILLS - EXCLUDING TAXES

kWh	AVERAGE MONTHLY BILL
100	$14.92
150	$18.27
200	$21.61
250	$24.97
300	$28.31
350	$31.66
400	$35.01
450	$38.36
500	$41.70
550	$45.06
600	$48.40
650	$51.75
700	$55.10
750	$58.45
800	$61.18
850	$63.92
900	$66.65
950	$69.39
1000	$72.12
1100	$77.59
1200	$83.06
1300	$88.53
1400	$94.00
1500	$99.47
1600	$104.94
1700	$110.41
1800	$115.88
1900	$121.35
2000	$126.82
2500	$154.17
3000	$181.52
3500	$208.87
4000	$236.22
4500	$263.57
5000	$290.92

MISSOURI
SMALL GENERAL SERVICE CLASSIFICATION NO. 2(M)
TYPICAL MONTHLY BILLS - EXCLUDING TAXES
SINGLE-PHASE SERVICE

kWh	AVERAGE MONTHLY BILL
0	$9.50
50	$13.28
100	$17.06
300	$32.18
400	$39.74
500	$47.30
600	$54.86
700	$62.42
800	$69.98
900	$77.54
1000	$85.10
2,000	$160.70
3,000	$236.30
4,000	$311.90
5,000	$387.50
6,000	$463.10
7,000	$538.70
8,000	$614.30
9,000	$689.90
10,000	$765.50
11,000	$841.10
12,000	$916.70
13,000	$992.30
14,000	$1,067.90
15,000	$1,143.50
16,000	$1,219.10
17,000	$1,294.70
18,000	$1,370.30
19,000	$1,445.90
20,000	$1,521.50
21,000	$1,597.10
22,000	$1,672.70
23,000	$1,748.30
24,000	$1,823.90
25,000	$1,899.50
30,000	$2,277.50
35,000	$2,655.50
40,000	$3,033.50
45,000	$3,411.50
50,000	$3,789.50

(1) - WINTER BILLS EXCLUDE SEASONAL USAGE EFFECT, IF ANY.

MISSOURI
SMALL GENERAL SERVICE CLASSIFICATION NO. 2(M)
TYPICAL MONTHLY BILLS - EXCLUDING TAXES
THREE-PHASE SERVICE

kWh	AVERAGE MONTHLY BILL
0	$19.00
50	$22.78
100	$26.56
300	$41.68
400	$49.24
500	$56.80
600	$64.36
700	$71.92
800	$79.48
900	$87.04
1000	$94.60
2,000	$170.20
3,000	$245.80
4,000	$321.40
5,000	$397.00
6,000	$472.60
7,000	$548.20
8,000	$623.80
9,000	$699.40
10,000	$775.00
11,000	$850.60
12,000	$926.20
13,000	$1,001.80
14,000	$1,077.40
15,000	$1,153.00
16,000	$1,228.60
17,000	$1,304.20
18,000	$1,379.80
19,000	$1,455.40
20,000	$1,531.00
21,000	$1,606.60
22,000	$1,682.20
23,000	$1,757.80
24,000	$1,833.40
25,000	$1,909.00
30,000	$2,287.00
35,000	$2,665.00
40,000	$3,043.00
45,000	$3,421.00
50,000	$3,799.00

(1) - WINTER BILLS EXCLUDE SEASONAL USAGE EFFECT, IF ANY.

MISSOURI
LARGE GENERAL SERVICE CLASSIFICATION NO. 3(M)
TYPICAL MONTHLY BILLS - EXCLUDING TAXES

kW	kWh/kW	kWh	AVERAGE MONTHLY BILL
100	100	10,000	$1,014.00
	200	20,000	$1,577.17
	300	30,000	$2,090.17
	400	40,000	$2,513.83
	500	50,000	$2,848.17
	600	60,000	$3,182.50
	700	70,000	$3,516.83
500	100	50,000	$4,806.00
	200	100,000	$7,621.83
	300	150,000	$10,186.83
	400	200,000	$12,305.17
	500	250,000	$13,976.83
	600	300,000	$15,648.50
	700	350,000	$17,320.17
1000	100	100,000	$9,546.00
	200	200,000	$15,177.67
	300	300,000	$20,307.67
	400	400,000	$24,544.33
	500	500,000	$27,887.67
	600	600,000	$31,231.00
	700	700,000	$34,574.33
2,000	100	200,000	$19,026.00
	200	400,000	$30,289.33
	300	600,000	$40,549.33
	400	800,000	$49,022.67
	500	1,000,000	$55,709.33
	600	1,200,000	$62,396.00
	700	1,400,000	$69,082.67
3,000	100	300,000	$28,506.00
	200	600,000	$45,401.00
	300	900,000	$60,791.00
	400	1,200,000	$73,501.00
	500	1,500,000	$83,531.00
	600	1,800,000	$93,561.00
	700	2,100,000	$103,591.00
5,000	100	500,000	$47,466.00
	200	1,000,000	$75,624.33
	300	1,500,000	$101,274.33
	400	2,000,000	$122,457.67
	500	2,500,000	$139,174.33
	600	3,000,000	$155,891.00
	700	3,500,000	$172,607.67

(1) - WINTER BILLS EXCLUDE SEASONAL USAGE EFFECT, IF ANY.

MISSOURI
SMALL PRIMARY SERVICE CLASSIFICATION NO. 4(M)
TYPICAL MONTHLY BILLS - EXCLUDING TAXES

kW	kWh/kW	kWh	AVERAGE MONTHLY BILL
100	100	10,000	$1,123.33
	200	20,000	$1,677.17
	300	30,000	$2,181.50
	400	40,000	$2,597.83
	500	50,000	$2,926.17
	600	60,000	$3,254.50
	700	70,000	$3,582.83
500	100	50,000	$4,776.67
	200	100,000	$7,545.83
	300	150,000	$10,067.50
	400	200,000	$12,149.17
	500	250,000	$13,790.83
	600	300,000	$15,432.50
	700	350,000	$17,074.17
1000	100	100,000	$9,343.33
	200	200,000	$14,881.67
	300	300,000	$19,925.00
	400	400,000	$24,088.33
	500	500,000	$27,371.67
	600	600,000	$30,655.00
	700	700,000	$33,938.33
2,000	100	200,000	$18,476.67
	200	400,000	$29,553.33
	300	600,000	$39,640.00
	400	800,000	$47,966.67
	500	1,000,000	$54,533.33
	600	1,200,000	$61,100.00
	700	1,400,000	$67,666.67
3,000	100	300,000	$27,610.00
	200	600,000	$44,225.00
	300	900,000	$59,355.00
	400	1,200,000	$71,845.00
	500	1,500,000	$81,695.00
	600	1,800,000	$91,545.00
	700	2,100,000	$101,395.00
5,000	100	500,000	$45,876.67
	200	1,000,000	$73,568.33
	300	1,500,000	$98,785.00
	400	2,000,000	$119,601.67
	500	2,500,000	$136,018.33
	600	3,000,000	$152,435.00
	700	3,500,000	$168,851.67

(1) - WINTER BILLS EXCLUDE SEASONAL USAGE EFFECT, IF ANY.

MISSOURI
LARGE PRIMARY SERVICE CLASSIFICATION NO. 11(M)
TYPICAL MONTHLY BILLS - EXCLUDING TAXES

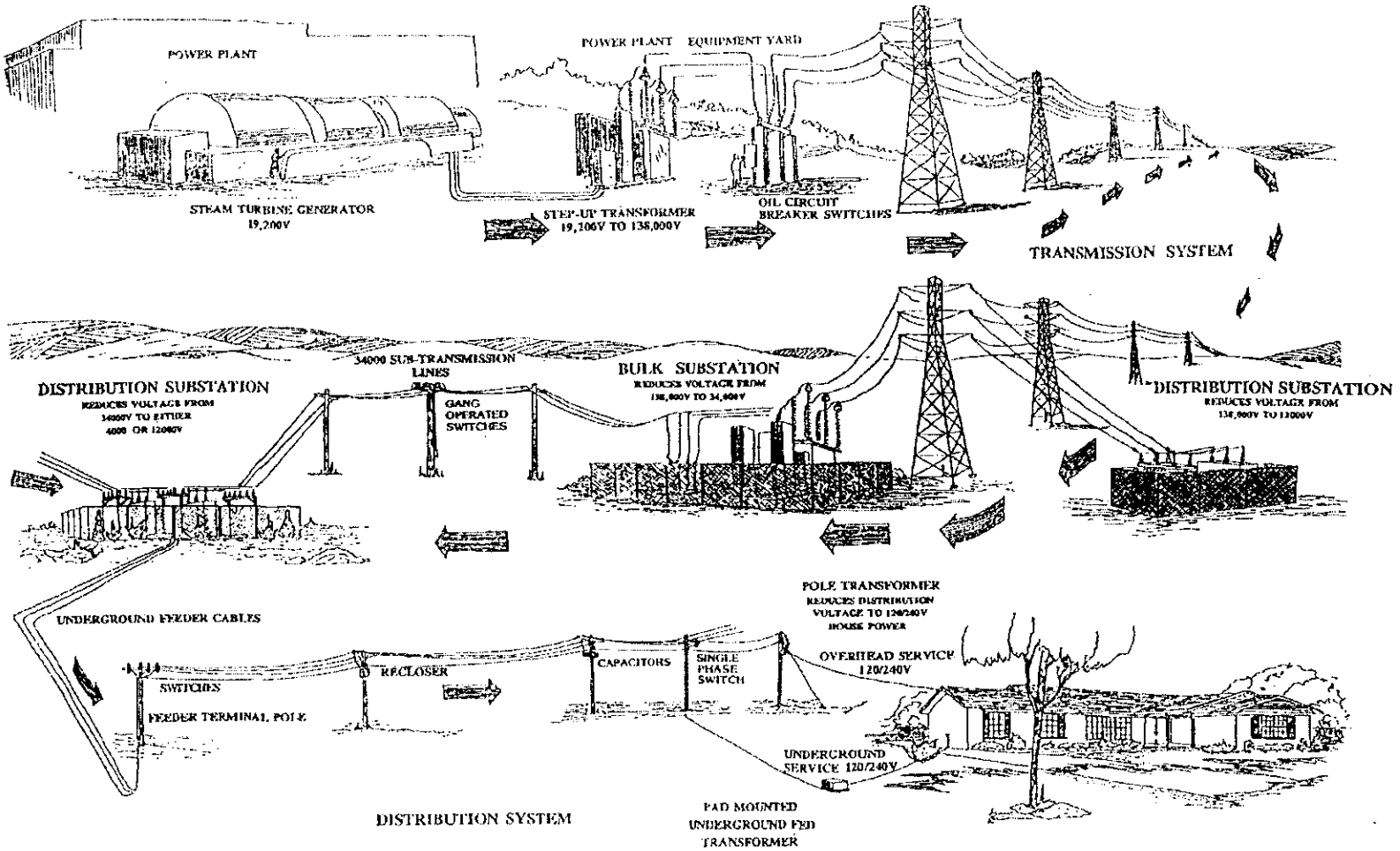
	kW	kWh/kW	kWh	AVERAGE MONTHLY BILL
*	4,000	300	1,200,000	$102,560.00
		400	1,600,000	$114,613.33
		500	2,000,000	$126,666.67
		600	2,400,000	$131,488.00
		700	2,800,000	$142,336.00
	5,000	300	1,500,000	$111,600.00
		400	2,000,000	$126,666.67
		500	2,500,000	$141,733.33
		600	3,000,000	$147,760.00
		700	3,500,000	$161,320.00
	10,000	300	3,000,000	$222,800.00
		400	4,000,000	$252,933.33
		500	5,000,000	$283,066.67
		600	6,000,000	$295,120.00
		700	7,000,000	$322,240.00
	20,000	300	6,000,000	$445,200.00
		400	8,000,000	$505,466.67
		500	10,000,000	$565,733.33
		600	12,000,000	$589,840.00
		700	14,000,000	$644,080.00
	30,000	300	9,000,000	$667,600.00
		400	12,000,000	$758,000.00
		500	15,000,000	$848,400.00
		600	18,000,000	$884,560.00
		700	21,000,000	$965,920.00
	50,000	300	15,000,000	$1,112,400.00
		400	20,000,000	$1,263,066.67
		500	25,000,000	$1,413,733.33
		600	30,000,000	$1,474,000.00
		700	35,000,000	$1,609,600.00
	100,000	300	30,000,000	$2,224,400.00
		400	40,000,000	$2,525,733.33
		500	50,000,000	$2,827,066.67
		600	60,000,000	$2,947,600.00
		700	70,000,000	$3,218,800.00

* - BILLS REFLECT MINIMUM BILLING DEMAND OF 5,000 kW.

MISSOURI
LARGE TRANSMISSION SERVICE CLASSIFICATION NO. 12(M)
TYPICAL MONTHLY BILLS - EXCLUDING TAXES

	kW	kWh/kW	kWh	AVERAGE MONTHLY BILL
*	4,000	300	1,200,000	$77,880.00
		400	1,600,000	$88,973.33
		500	2,000,000	$100,066.67
		600	2,400,000	$111,160.00
		700	2,800,000	$122,253.33
	5,000	300	1,500,000	$86,200.00
		400	2,000,000	$100,066.67
		500	2,500,000	$113,933.33
		600	3,000,000	$127,800.00
		700	3,500,000	$141,666.67
	10,000	300	3,000,000	$172,000.00
		400	4,000,000	$199,733.33
		500	5,000,000	$227,466.67
		600	6,000,000	$255,200.00
		700	7,000,000	$282,933.33
	20,000	300	6,000,000	$343,600.00
		400	8,000,000	$399,066.67
		500	10,000,000	$454,533.33
		600	12,000,000	$510,000.00
		700	14,000,000	$565,466.67
	30,000	300	9,000,000	$515,200.00
		400	12,000,000	$598,400.00
		500	15,000,000	$681,600.00
		600	18,000,000	$764,800.00
		700	21,000,000	$848,000.00
	50,000	300	15,000,000	$858,400.00
		400	20,000,000	$997,066.67
		500	25,000,000	$1,135,733.33
		600	30,000,000	$1,274,400.00
		700	35,000,000	$1,413,066.67
	100,000	300	30,000,000	$1,716,400.00
		400	40,000,000	$1,993,733.33
		500	50,000,000	$2,271,066.67
		600	60,000,000	$2,548,400.00
		700	70,000,000	$2,825,733.33

GENERATING AND POWER DISTRIBUTION SYSTEM



Schedule WLC-E4

AmerenUE
MISSOURI ELECTRIC OPERATIONS
ELECTRIC COST OF SERVICE ALLOCATION STUDY
12 MONTHS ENDED JUNE 2006

	TITLE: SUMMARY	MISSOURI	RESIDENTIAL	SMALL GEN SERV	LARGE GEN SERV	SMALL PRIMARY	LARGE PRIMARY	LARGE TRANS
1	BASE REVENUE	$ 1,970,790	$ 850,213	$ 226,710	$ 418,267	$ 182,440	$ 155,952	$ 137,209
2	OTHER REVENUE	$ 62,831	$ 32,743	$ 6,417	$ 10,700	$ 4,656	$ 4,991	$ 3,324
3	LIGHTING REVENUE	$ 27,111	$ 13,515	$ 3,093	$ 5,129	$ 2,117	$ 2,024	$ 1,231
4	SYSTEM REVENUE	$ 305,352	$ 141,552	$ 34,164	$ 60,213	$ 26,163	$ 25,343	$ 17,917
5	RATE REVENUE VARIANCE	$ (22)	$ (11)	$ (2)	$ (4)	$ (2)	$ (2)	$ (1)
6	TOTAL OPERATING REVENUE	$ 2,366,061	$ 1,038,013	$ 270,381	$ 494,305	$ 215,374	$ 188,307	$ 159,680
7								
8	TOTAL PROD, T&D, CUST, AND A&G EXP	$ 1,466,770	$ 631,615	$ 151,370	$ 290,712	$ 138,649	$ 140,403	$ 114,022
9	TOTAL DEPR AND AMMORT EXPENSES	$ 386,941	$ 197,618	$ 44,796	$ 72,330	$ 28,930	$ 27,432	$ 15,834
10	REAL ESTATE AND PROPERTY TAXES	$ 99,528	$ 50,795	$ 11,520	$ 18,610	$ 7,447	$ 7,065	$ 4,092
11	INCOME TAXES	$ 233,191	$ 116,251	$ 26,604	$ 44,120	$ 18,212	$ 17,410	$ 10,592
12	PAYROLL TAXES	$ 19,601	$ 9,331	$ 2,093	$ 3,657	$ 1,732	$ 1,700	$ 1,087
13	FEDERAL EXCISE TAX	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	REVENUE TAXES	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15								
16	TOTAL OPERATING EXPENSES	$ 2,206,031	$ 1,005,611	$ 236,384	$ 429,429	$ 194,970	$ 194,009	$ 145,627
17								
18	NET OPERATING INCOME	$ 160,030	$ 32,402	$ 33,997	$ 64,876	$ 20,404	$ (5,702)	$ 14,053
19								
20	GROSS PLANT IN SERVICE	$ 11,224,426	$ 5,727,483	$ 1,298,968	$ 2,098,760	$ 840,189	$ 797,165	$ 461,861
21	RESERVES FOR DEPRECIATION	$ 4,500,562	$ 2,336,943	$ 524,193	$ 834,584	$ 324,668	$ 306,876	$ 173,298
22								
23	NET PLANT IN SERVICE	$ 6,723,865	$ 3,390,540	$ 774,776	$ 1,264,176	$ 515,521	$ 490,289	$ 288,563
24								
25	MATERIALS & SUPPLIES - FUEL	$ 227,226	$ 83,227	$ 22,416	$ 49,074	$ 24,304	$ 25,033	$ 23,172
26	MATERIALS & SUPPLIES -LOCAL	$ 21,434	$ 13,180	$ 2,694	$ 3,557	$ 1,060	$ 914	$ 29
27	CASH WORKING CAPITAL	$ (13,595)	$ (5,854)	$ (1,403)	$ (2,695)	$ (1,285)	$ (1,301)	$ (1,057)
28	CUSTOMER ADVANCES & DEPOSITS	$ (14,677)	$ (6,243)	$ (4,406)	$ (2,673)	$ (845)	$ (511)	$ -
29	ACCUMULATED DEFERRED INCOME TAXES	$ (1,095,577)	$ (559,136)	$ (126,813)	$ (204,854)	$ (81,970)	$ (77,764)	$ (45,040)
30								
31	TOTAL NET ORIGINAL COST RATE BASE	$ 5,848,677	$ 2,915,713	$ 667,264	$ 1,106,586	$ 456,786	$ 436,660	$ 265,668
32								
33	RATE OF RETURN	2.736%	1.111%	5.095%	5.863%	4.467%	-1.306%	5.290%

AmerenUE
MISSOURI ELECTRIC OPERATIONS
EQUALIZED CLASS RATES OF RETURN ANALYSIS
12 MONTHS ENDED JUNE 2006

	TITLE: SUMMARY EQUAL ROR ($000's)	MISSOURI	RESIDENTIAL	SMALL GEN SERV	LARGE GEN SERV	SMALL PRIMARY	LARGE PRIMARY	LARGE TRANS
1	BASE REVENUE	$ 2,331,499	$ 1,078,160	$ 251,997	$ 451,572	$ 202,566	$ 200,486	$ 146,718
2	OTHER REVENUE	$ 62,831	$ 32,743	$ 6,417	$ 10,700	$ 4,656	$ 4,991	$ 3,324
3	LIGHTING REVENUE	$ 27,111	$ 13,515	$ 3,093	$ 5,129	$ 2,117	$ 2,024	$ 1,231
4	SYSTEM REVENUE	$ 305,352	$ 141,552	$ 34,164	$ 60,213	$ 26,163	$ 25,343	$ 17,917
5	RATE REVENUE VARIANCE	$ (22)	$ (11)	$ (2)	$ (4)	$ (2)	$ (2)	$ (1)
6	TOTAL OPERATING REVENUE	$ 2,726,770	$ 1,265,960	$ 295,668	$ 527,610	$ 235,500	$ 232,842	$ 169,189
7								
8	TOTAL PROD., T&D, CUSTOMER, AND A&G EXP.	$ 1,468,790	$ 633,370	$ 151,474	$ 290,750	$ 138,667	$ 140,508	$ 114,022
9	TOTAL DEPR. AND AMMOR. EXPENSES	$ 386,941	$ 197,618	$ 44,796	$ 72,330	$ 28,930	$ 27,432	$ 15,834
10	REAL ESTATE AND PROPERTY TAXES	$ 99,528	$ 50,795	$ 11,520	$ 18,610	$ 7,447	$ 7,065	$ 4,092
11	INCOME TAXES	$ 233,191	$ 116,251	$ 26,604	$ 44,120	$ 18,212	$ 17,410	$ 10,592
12	PAYROLL TAXES	$ 19,601	$ 9,331	$ 2,093	$ 3,657	$ 1,732	$ 1,700	$ 1,087
13	FEDERAL EXCISE TAX	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	REVENUE TAXES	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15								
16	TOTAL OPERATING EXPENSES	$ 2,208,051	$ 1,007,366	$ 236,489	$ 429,467	$ 194,988	$ 194,114	$ 145,627
17								
18	NET OPERATING INCOME	$ 518,719	$ 258,595	$ 59,180	$ 98,143	$ 40,512	$ 38,727	$ 23,562
19								
20	GROSS PLANT IN SERVICE	$11,224,426	$ 5,727,483	$ 1,298,968	$ 2,098,760	$ 840,189	$ 797,165	$ 461,861
21	RESERVES FOR DEPRECIATION	$ 4,500,562	$ 2,336,943	$ 524,193	$ 834,584	$ 324,668	$ 306,876	$ 173,298
22								
23	NET PLANT IN SERVICE	$ 6,723,865	$ 3,390,540	$ 774,776	$ 1,264,176	$ 515,521	$ 490,289	$ 288,563
24								
25	MATERIALS & SUPPLIES - FUEL	$ 227,226	$ 83,227	$ 22,416	$ 49,074	$ 24,304	$ 25,033	$ 23,172
26	MATERIALS & SUPPLIES -LOCAL	$ 21,434	$ 13,180	$ 2,694	$ 3,557	$ 1,060	$ 914	$ 29
27	CASH WORKING CAPITAL	$ (13,595)	$ (5,854)	$ (1,403)	$ (2,695)	$ (1,285)	$ (1,301)	$ (1,057)
28	CUSTOMER ADVANCES & DEPOSITS	$ (14,677)	$ (6,243)	$ (4,406)	$ (2,673)	$ (845)	$ (511)	$ -
29	ACCUMULATED DEFERRED INCOME TAXES	$ (1,095,577)	$ (559,136)	$ (126,813)	$ (204,854)	$ (81,970)	$ (77,764)	$ (45,040)
30								
31	TOTAL NET ORIGINAL COST RATE BASE	$ 5,848,677	$ 2,915,713	$ 667,264	$ 1,106,586	$ 456,786	$ 436,660	$ 265,668
32								
33	RATE OF RETURN	8.869%	8.869%	8.869%	8.869%	8.869%	8.869%	8.869%

AmerenUE
CASE NO. ER-2007-
DEVELOPMENT OF CLASS REVENUES WITH 10% RESIDENTIAL RATE CAP
($000's)

Class Cost of Service Revenue Requirements
Before Adjustment to Reflect Residential Rate Cap Increase of 10%

Customer Class	Current Base Revenue	Proposed Revenue @ Equal ROR	Equal ROR Revenue Adjustment	Equal ROR % Change
Residential	$ 850,202	$ 1,078,149	$ 227,947	26.8%
Small General Service	$ 226,708	$ 251,994	$ 25,286	11.2%
Large General Service	$ 418,263	$ 451,568	$ 33,305	8.0%
Small Primary Service	$ 182,438	$ 202,564	$ 20,126	11.0%
Large Primary Service	$ 155,950	$ 200,484	$ 44,534	28.6%
Large Transmission Service	$ 137,208	$ 146,717	$ 9,509	6.9%
Total	$ 1,970,769	$ 2,331,477	$ 360,708	18.3%

Class Revenue Requirements
After Adjustment to Reflect Residential Rate Cap Increase of 10%

Customer Class	Current Base Revenue	Residential Rate Cap Proposed Revenue	Residential Rate Cap Revenue Adjustment	Residential Rate Cap % Change
Residential	$ 850,202	$ 935,222	$ 85,020	10.0%
Small General Service	$ 226,708	$ 280,731	$ 54,023	23.8%
Large General Service	$ 418,263	$ 503,064	$ 84,801	20.3%
Small Primary Service	$ 182,438	$ 225,664	$ 43,226	23.7%
Large Primary Service	$ 155,950	$ 223,347	$ 67,397	43.2%
Large Transmission Service	$ 137,208	$ 163,448	$ 26,240	19.1%
Total	$ 1,970,769	$ 2,331,477	$ 360,708	18.3%

AmerenUE
MISSOURI ELECTRIC OPERATIONS
CLASS COST OF SERVICE ALLOCATION STUDY
12 MONTHS ENDED JUNE 2006

	Total Missouri	Residential	Small Gen Serv	Large Gen Serv	Small Primary	Large Primary	Large Lg Trans
Unbundled Class Cost of Service ($000's)							
Customer	$ 139,183	$ 115,416	$ 16,672	$ 5,030	$ 1,050	$ 1,014	$ 1
Production -- Demand	$ 879,465	$ 410,165	$ 97,518	$ 171,846	$ 75,656	$ 73,386	$ 50,892
Production -- Energy	$ 917,295	$ 336,242	$ 90,202	$ 197,488	$ 98,370	$ 101,420	$ 93,573
Transmission -- Demand	$ 22,365	$ 10,041	$ 2,259	$ 4,138	$ 2,136	$ 2,181	$ 1,609
Distribution -- Demand	$ 373,169	$ 206,284	$ 45,342	$ 73,066	$ 25,351	$ 22,483	$ 642
	$ 2,331,477	$ 1,078,149	$ 251,994	$ 451,568	$ 202,564	$ 200,484	$ 146,717

UNION ELECTRIC COMPANY
MISSOURI
CASE NO. ER-2007-
PROPOSED UNBUNDLED CLASS REVENUE REQUIREMENTS
(REFLECTS IMPACT OF RESIDENTIAL RATE CAP INCREASE OF 10%)
($000's)

	Total Missouri	Residential	Small Gen Serv	Large Gen Serv	Small Primary	Large Primary	Large Lg Trans
Customer	$ 182,448	$ 100,116	$ 18,574	$ 5,604	$ 1,170	$ 1,129	$ 1
Production -- Demand	$ 1,003,615	$ 355,791	$ 108,639	$ 191,443	$ 84,284	$ 81,755	$ 56,695
Production -- Energy	$ 1,002,259	$ 291,667	$ 100,489	$ 220,009	$ 109,588	$ 112,986	$ 104,244
Transmission -- Demand	$ 110,941	$ 8,710	$ 2,517	$ 4,610	$ 2,380	$ 2,429	$ 1,792
Distribution -- Demand	$ 425,486	$ 178,938	$ 50,512	$ 81,398	$ 28,242	$ 25,047	$ 716
	$ 2,724,750	$ 935,222	$ 280,731	$ 503,064	$ 225,664	$ 223,347	$ 163,448

Residential Service Rate
AmerenUE - Missouri
Weather Normalized-12 months ending June 2006
April-June Forecast

Billing Components		Proposed
Summer (June - September)		
Customer Charge	Per Month	$8.22
Customer Charge TOD	Per Month	$16.50
Energy Charge:		
All Kwh	Cents per Kwh	8.95 ¢
TOD On Peak	Cents per Kwh	12.22 ¢
TOD Off Peak	Cents per Kwh	5.02 ¢
Winter (October - May)		
Customer Charge	Per Month	$8.22
Customer Charge TOD	Per Month	$16.50
Energy Charge:		
0- 750 Kwh	Cents per Kwh	5.57 ¢
All Kwh Over 750	Cents per Kwh	3.73 ¢
TOD On Peak	Cents per Kwh	7.21 ¢
TOD Off Peak	Cents per Kwh	3.56 ¢

Proof of Revenue

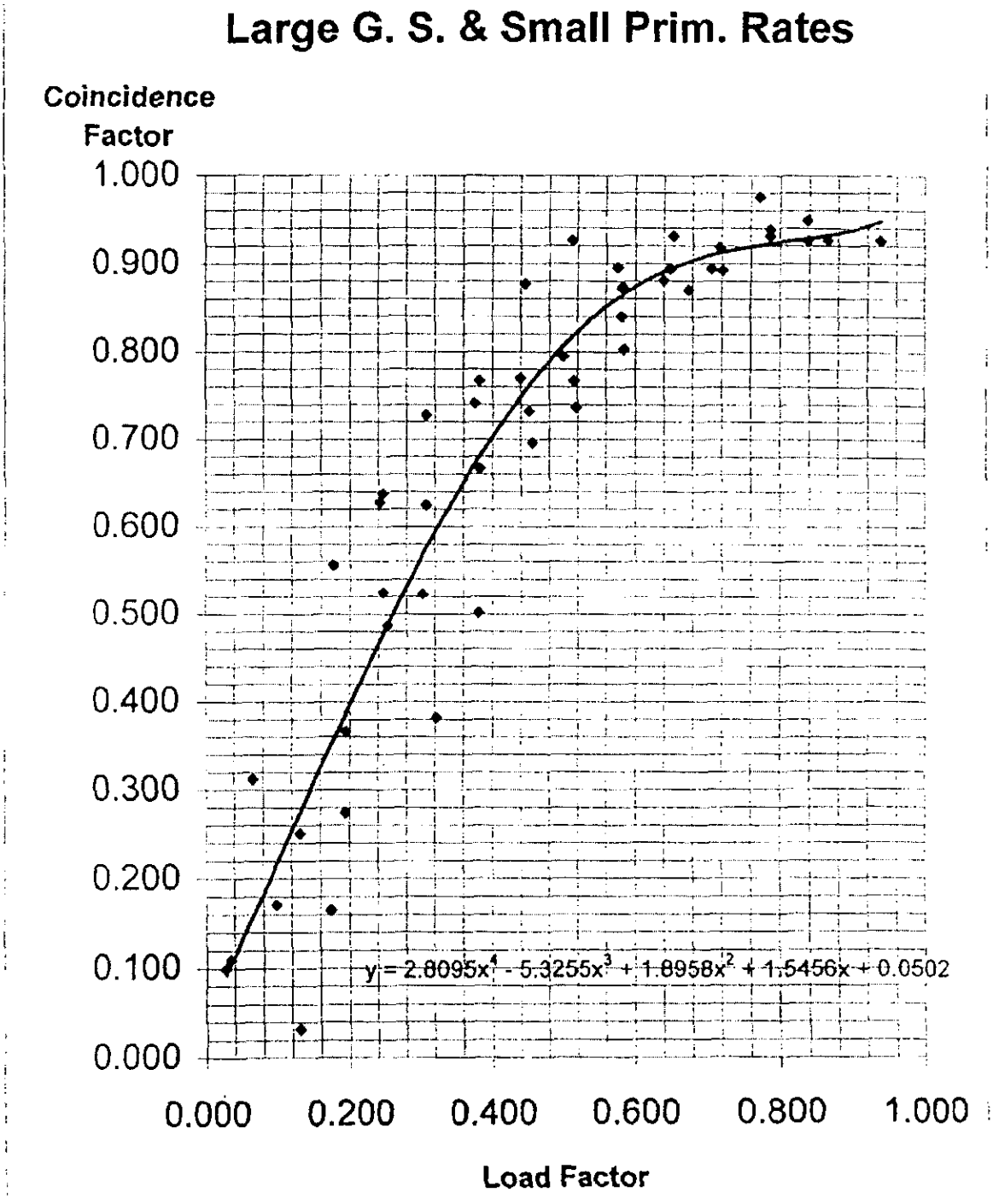
	Units	Rate	$1,000
Summer			
Customer Charge	4,047,891	$8.22	$33,274
Customer Charge TOD	108	$16.50	$2
Mwh	4,842,999	$0.08950	$433,448
TOD On Peak Kwh	141	$0.12220	$17
TOD Off Peak Kwh	307	$0.05020	$15
	4,843,447		$466,756
Winter			
Customer Charge	8,122,335	$8.22	$66,766
Customer Charge TOD	217	$16.50	$4
0-750 Mwh	4,979,288	$0.05570	$277,346
Over 750 Mwh	3,334,003	$0.03730	$124,358
TOD On Peak Kwh	287	$0.07210	$21
TOD Off Peak Kwh	578	$0.03560	$21
Total MWH	8,314,156		$468,515
Total Res	13,157,603		$935,272

Small General Service Rate
AmerenUE - Missouri
Weather Normalized-12 months ending June 2006
April-June Forecast

Billing Components		Present
Summer (June - September)		
Customer Charge:		
Single Phase Service	Per Month	$9.50
Three Phase Service	Per Month	$19.00
Single Phase Service TOD	Per Month	$19.00
Three Phase Service TOD	Per Month	$38.00
Energy Charge:		
All Kwh	Cents per Kwh	10.40 ¢
TOD On Peak	Cents per Kwh	13.65 ¢
TOD Off Peak	Cents per Kwh	5.57 ¢
Winter (October - May)		
Customer Charge:		
Single Phase Service	Per Month	$9.50
Three Phase Service	Per Month	$19.00
Single Phase Service TOD	Per Month	$19.00
Three Phase Service TOD	Per Month	$38.00
Energy Charge:		
Base Use	Cents per Kwh	6.14 ¢
Seasonal Use	Cents per Kwh	3.28 ¢
TOD On Peak	Cents per Kwh	8.99 ¢
TOD Off Peak	Cents per Kwh	4.13 ¢

Proof of Revenue

	Units	Rate	1000's
Summer			
Customer Charge - Single Phase	369,238	$9.50	$3,508
Customer Charge - Three Phase	139,514	$19.00	$2,651
Single Phase Service TOD	544	$19.00	$10
Three Phase Service TOD	281	$38.00	$11
Mwh	1,268,678	$0.1040	$131,942
TOD On Peak Kwh	2,684	$0.1365	$366
TOD Off Peak Kwh	4,684	$0.0557	$260
Summer Total MWH	1,276,026		$138,748
Winter			
Customer Charge - Single Phase	740,475	$9.50	$7,035
Customer Charge - Three Phase	281,232	$19.00	$5,343
Single Phase Service TOD	1,340	$19.00	$25
Three Phase Service TOD	585	$38.00	$22
Winter Base Mwh	1,871,325	$0.0614	$114,899
Winter Seasonal Mwh	419,840	$0.0328	$13,771
TOD On Peak Kwh	5,298	$0.0899	$476
TOD Off Peak Kwh	9,389	$0.0413	$388
Winter Total MWH	2,305,852		$141,960
Total	3,581,878		$280,708


Large G. S. & Small Prim. Rates
Coincidence Factor
1.000
0.900
0.800
0.700
0.600
0.500
0.400
0.300
0.200
0.100
0.000
y = 2.8095x⁴ - 5.3255x³ + 1.8958x² + 1.5456x + 0.0502
0.000
0.200
0.400
0.600
0.800
1.000
Load Factor

Large General Service Rate
AmerenUE - Missouri
Weather Normalized-12 months ending June 2006
April-June Forecast

Billing Components		Proposed
Summer (June - September)		
Customer Charge	Per Month	$66.00
Customer Charge TOD	Per Month	$80.00
Energy Charge (¢ per kWh)		
First 150 kWh per KW		8.24 ¢
Next 200 kWh per KW		6.61 ¢
All over 350 kWh per KW		3.73 ¢
TOD On Peak Adjust. per Kwh		0.88 ¢
TOD Off Peak Adjust. per Kwh		-0.49 ¢
Demand		
Per KW of Billing Demand		$5.02
Winter (October - May)		
Customer Charge	Per Month	$66.00
Customer Charge TOD	Per Month	$80.00
Energy Charge (¢ per kWh)		
First 150 kWh per KW		5.08 ¢
Next 200 kWh per KW		4.39 ¢
All over 350 kWh per KW		3.15 ¢
Seasonal Energy Charge		3.15 ¢
TOD On Peak Adjust. per Kwh		0.27 ¢
TOD Off Peak Adjust. per Kwh		-0.15 ¢
Demand		
Per KW of Billing Demand		$2.51

Proof of Revenue

	Units	Rate	$1,000
Summer			
Customer Charge	37,552	$66.00	$2,478
Customer Charge TOD	84	$80.00	$7
Summer Energy Mwh			
0-150 hours	1,139,107	$0.0824	$93,862
151-350 hours	1,222,263	$0.0661	$80,792
Over 350 hours	494,132	$0.0373	$18,431
Seasonal	113	$0.0000	$0
TOD On Peak	2,000	$0.0088	$18
TOD Off Peak	3,158	-$0.0049	-$15
Demand	8,319,125	$5.02	$41,762
			$237,334
Winter			
Customer Charge	75,312	$66.00	$4,971
Customer Charge TOD	168	$80.00	$13
Winter Energy Mwh			
0-150 hours	1,897,091	$0.0508	$96,372
151-350 hours	2,021,758	$0.0439	$88,755
Over 350 hours	852,489	$0.0315	$26,853
Seasonal	334,520	$0.0315	$10,537
TOD On Peak	3,288	$0.0027	$9
TOD Off Peak	5,172	-$0.0015	-$8
Demand	15,226,610	$2.51	$38,219
			$265,722
	7,961,473		$503,057

Small Primary Service Rate
AmerenUE - Missouri
Weather Normalized-12 months ending June 2006
April-June Forecast

Billing Components		Proposed
Summer (June - September)		
Customer Charge	Per Month	$210.00
Customer Charge TOD	Per Month	$224.00
Energy Charge (¢ per kWh)		
First 150 kWh per KW		8.06 ¢
Next 200 kWh per KW		6.47 ¢
All over 350 kWh per KW		3.65 ¢
TOD On Peak Adjust. per Kwh		0.63 ¢
TOD Off Peak Adjust. per Kwh		-0.35 ¢
Demand		
Per KW of Billing Demand		$4.64
Billing Kvars		24 ¢
Rider B 34kv		
Per KW		81 ¢
Rider B 138kv		
Per KW		95 ¢
Winter (October - May)		
Customer Charge	Per Month	$210.00
Customer Charge TOD	Per Month	$224.00
Energy Charge (¢ per kWh)		
First 150 kWh per KW		5.02 ¢
Next 200 kWh per KW		4.33 ¢
All over 300 kWh per KW		3.10 ¢
Seasonal Energy Charge		3.1 ¢
TOD On Peak Adjust. per Kwh		0.23 ¢
TOD Off Peak Adjust. per Kwh		-0.13 ¢
Demand		
Per KW of Billing Demand		$2.33
Billing Kvars		24 ¢
Rider B 34kv		
Per KW		81 ¢
Rider B 138kv		
Per KW		95 ¢

Proof of Revenue

	Units	Rate	$1,000
Summer			
Customer Charge	2,563	$210.00	$538
Customer Charge TOD	19	$224.00	$4
Summer Energy Mwh			
0-150 hours	466,903	$0.0806	$37,632
151-350 hours	530,728	$0.0647	$34,338
Over 350 hours	465,948	$0.0365	$17,007
Seasonal	-4,804	$0.0000	$0
TOD On Peak	5,182	$0.0063	$33
TOD Off Peak	7,926	-$0.0035	($28)
Demand	3,205,417	$4.64	$14,873
Billing Kvars	618,614	$0.24	$148
Rider B 34kv	324,507	$0.81	($263)
Rider B 138kv	0	$0.95	$0
			$104,284
Winter			
Customer Charge	5,078	$210.00	$1,066
Customer Charge TOD	40	$224.00	$9
Winter Energy Mwh			
0-150 hours	780,677	$0.0502	$39,190
151-350 hours	926,556	$0.0433	$40,120
Over 350 hours	745,533	$0.0310	$23,112
Seasonal	155,255	$0.0310	$4,813
TOD On Peak	10,205	$0.0023	$23
TOD Off Peak	16,333	-$0.0013	($21)
Demand	5,685,807	$2.33	$13,248
Billing Kvars	1,226,639	$0.24	$294
Rider B 34kv	563,733	$0.81	($457)
Rider B 138kv	0	$0.95	$0
			$121,398
	4,066,796		$225,681

Large Primary Service Rate
AmerenUE - Missouri
Weather Normalized-12 months ending June 2006
April-June Forecast

Billing Components		Proposed
Summer (June - September)		
Customer Charge	Per Month	$400.00
Demand Charge	Per KW of Billing Demand	$19.80
Energy Charge:		
All Kwh	Cents per Kwh	3.22 ¢
TOD On Peak Adjust. per Kwh		0.45 ¢
TOD Off Peak Adjust. per Kwh		-0.25 ¢
10% Discount for over 80% Load Factor		0.322 ¢
Reactive Charge	Cents per kVar	24 ¢
Rider B 34kv	Per KW	81 ¢
Rider B 138kv	Per KW	95 ¢
Winter (October - May)		
Customer Charge	Per Month	$400.00
Demand Charge	Per KW of Billing Demand	$9.90
Energy Charge:		
All Kwh	Cents per Kwh	2.91 ¢
TOD On Peak Adjust. per Kwh		0.2 ¢
TOD Off Peak Adjust. per Kwh		-0.11 ¢
10% Discount for over 80% Load Factor		0.291 ¢
Reactive Charge	Cents per kVar	24 ¢
Rider B 34kv	Per KW	81 ¢
Rider B 138kv	Per KW	95 ¢

Proof of Revenue

	Units	Rate	1000's
Summer			
Customer Charge	242	$400.00	$97
Summer Mwh	1,492,472	$0.0322	$48,058
TOD On Peak	29,851	$0.0045	$134
TOD Off Peak	51,376	-$0.0025	-$128
Demand	2,669,328	$19.80	$52,853
Billing Kvars	325,275	0.24	$78
Rider B 34kv	681,130	0.81	($552)
Rider B 138kv	177,388	0.95	($169)
10% Discount	136,218	0.00322	($439)
			$99,932
Winter			
Customer Charge	488	$400.00	$195
Winter Mwh	2,653,640	$0.0291	$77,221
TOD On Peak	49,855	$0.0020	$100
TOD Off Peak	93,028	-$0.0011	-$102
Demand	4,848,009	$9.90	$47,995
Billing Kvars	609,400	$0.24	$146
Rider B 34kv	1,267,707	$0.81	($1,027)
Rider B 138kv	355,245	$0.95	($337)
10% Discount	283,267	0.00291	($824)
			$123,366
	4,148,112		$223,299

Large Transmission Service Rate
AmerenUE - Missouri
Weather Normalized-12 months ending June 2006
April-June Forecast

Billing Components		Proposed
Summer (June - September)		
Customer Charge	Per Month	$400.00
Demand Charge	Per KW of Billing Demand	$13.26
Energy Charge:		
All Kwh	Cents per Kwh	2.94 ¢
Reactive Charge	Cents per kVar	24 ¢
Winter (October - May)		
Customer Charge	Per Month	$400.00
Demand Charge	Per KW of Billing Demand	$6.63
Energy Charge:		
All Kwh	Cents per Kwh	2.69 ¢
Reactive Charge	Cents per kVar	24 ¢

Proof of Revenue

	Units	Rate	1000's
Summer			
Customer Charge	4	$400.00	$2
Summer Mwh	1,351,282	$0.02940	$39,728
Demand	1,845,439	$13.26	$24,471
Billing Kvars	0	0.24	$0
			$64,200
Winter			
Customer Charge	8	$400.00	$3
Winter Mwh	2,712,757	$0.02690	$72,973
Demand	3,960,905	$6.63	$26,261
Billing Kvars	0	$0.24	$0
			$99,237
	4,064,039		$163,437