Exhibit No.
Issue: Accounting Schedules
Witness: Kelly S. Walters
Type of Exhibit: Direct Testimony
Sponsoring Party: Empire District
Case No.

**Before the Public Service Commission
of the State of Missouri**

Direct Testimony

of

Kelly S. Walters

April 2004

DIRECT TESTIMONY
OF
KELLY S. WALTERS
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION
CASE NO.

I. Introduction

Q. STATE YOUR NAME AND ADDRESS PLEASE.

A. Kelly S. Walters. My business address is 602 Joplin Street, Joplin, Missouri.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. The Empire District Electric Company ("Empire" or "Company"). I am the Director of Planning and Regulatory.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold Bachelor of Science degree in Business Administration with a major in accounting from Pittsburg State University. I began my employment with Empire in November 1988 in the accounting department where I held various positions. In July 1993 I became the Manager of Regulatory Accounting.

I left employment at Empire in 1998 to assume the position of Manager of Financial Services at Crowder College. In September 2001. I rejoined Empire as the Director of Planning and Regulatory. In this position I have responsibility for load research, strategic planning, rates, and regulatory accounting.

In October 2001, I received a Master of Arts degree in Human Resource Management from Webster University.

II. Purpose and Scope

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the schedules consisting of financial and other information included in this filing, which support the Company's proposed rate increase.

Q. WHAT TEST YEAR DID THE COMPANY USE IN DETERMINING RATE BASE, OPERATING INCOME AND RATE OF RETURN?

A. The schedules included in this filing are based on the twelve months ending December 31, 2003 adjusted for known and measurable changes.

Q. WHAT SCHEDULES ARE YOU SPONSORING?

A. I am sponsoring the following portions of the filing:

Section C, Schedule 1, Comparative and Summary Information

Section D, Schedule 1, Rate Base and Rate of Return

Section E, Schedule 1, Electric Plant in Service by Primary Plant Account

Section F, Schedule 1, Accumulated Provision for Depreciation of Electric Plant in Service

Section G, Schedule 1, Page 1, Working Capital

Section G, Schedule 1, Page 2, Materials and Supplies without Adjustments

Section G, Schedule 1, Page 3, Prepayments with Adjustments

Section G, Schedule 1, Page 4, Prepaid Interest

Section G, Schedule 2, Cash Working Capital

Section G, Schedule 3, Page 1 Income Tax Gross-up Factor

Section G, Schedule 3, Page 2, Income Tax Lag

Section G, Schedule 3, Page 3, Interest Expense Lag Calculation

Section G, Schedule 3, Page 4, Calculation of Interest Offset and Income Tax Offset

Section H, Schedule 1, Capital Structure at December 31, 2003

Section H, Schedule 2, Preferred Capital Stock

Section H, Schedule 3, Long Term Debt

Section H, Schedule 8, Capital Costs

Section J, Schedule 1, Test-Year Utility Operating Income Statements and Adjustments

Section J, Schedule 2, Explanation of Adjustments to Test-Year Revenues and Expenses

Section K, Schedule 1, Depreciation Rates and Accruals

Section K, Schedule 2, Page 1, Normalized Depreciation Expense

Section K, Schedule 2, Page 4, Summary of Depreciation and Amortization

Section L, Schedule 1, Taxes Charged to Electric Operations

Section L, Schedule 2, Page 1, Calculation of Provision for Income Taxes Payable for Twelve Months Ended December 31, 2003

Section L, Schedule 2, Page 2, Calculation of Deferred Income Taxes for Twelve

Months Ended December 31, 2003

Section M, Schedule 1, Bases of Allocation of Property and Expenses

Section M, Schedule 2, Page 1, Allocation of Rate Base

Section M, Schedule 2, Page 4, Allocation of Revenue and Expenses

Section N, Schedule 1-6, Cost of Service and Allocation Methodology

Q. WERE THESE SCHEDULES PREPARED UNDER YOUR SUPERVISION AND DIRECTION?

A. Yes, they were.

Q. WAS THIS FILING PREPARED IN ORDER TO ACHIEVE CONSISTENCY WITH EMPIRE'S PRIOR RATE FILINGS?

A. Yes. The filing was prepared in a manner consistent with our prior electric rate cases before the Missouri Public Service Commission ("Commission").

III. Schedule Explanations

Q. I DIRECT YOUR ATTENTION TO SECTION C, SCHEDULE 1 AND ASK YOU WHAT IT IS.

A. Section C, Schedule 1 is a summary of certain key data for the test year and comparison of this data with similar data from Empire's previous electric rate case, Case No. ER-2002-424.

Q. PLEASE ELABORATE ON SECTION D, SCHEDULE 1 RATE BASE AND RATE OF RETURN.

A. Section D, Schedule 1 details the Company's electric rate base and rate of return before and after the proposed rate increase.

For the test year ending December 31, 2003, end of period balances are used for electric plant in service and reserve for depreciation. Materials and supplies and prepayments are the average of the thirteen consecutive month-end balances ending December 31, 2003. In addition, the cash working capital requirement that is based on adjusted income has been added to rate base.

Injuries and damages reserve which represents the balance above the actual cash outlays, as well as deferred income taxes resulting from the use of liberalized depreciation methods are deducted from the rate base. Rate base has also been adjusted to reflect customer deposits and customer advances.

Interest offset, which is the cash lag in the interest synchronization calculation used to determine current income taxes, as well as income tax offset, which is the calculated current income tax times the lag in income tax payments, are also deducted from rate base.

The total original cost electric rate base is $611,396,947 (Line 14) which is multiplied by the indicated rate of return of 9.54% (Line 21) to arrive at after tax operating income of $58,327,269 (Line 20). This is subtracted from the proforma operating income of $26,051,602 (Line 15) which results in the after tax deficiency of $32,275,666 (Line 17) or the pre-tax revenue requirement of $52,385,889 (Line 19) which was filed with the Commission.

Q. PLEASE ADDRESS SECTION E, SCHEDULE 1, ELECTRIC PLANT IN SERVICE BY PRIMARY PLANT ACCOUNT.

A. Section E, Schedule 1, Pages 1 and 2 is a statement showing, by classified functional electric plant in service groups. the original cost of electric plant used and useful at December 31. 2002 and 2003. Total electric plant in service at December 31. 2003. is $1.189.777.270 (Column E) and $1.010.777.687 for Empire's Missouri jurisdiction (Column F).

Q. WILL YOU TELL US WHAT SECTION F. SCHEDULE 1 DEMONSTRATES?

A. Section F. Schedule 1 is a statement of accumulated provision for depreciation of electric plant in service showing amounts by functional plant groups at December 31, 2002 and 2003. The total accumulated provision for depreciation of electric plant in service at the end of the test year is $387,214,376 (Column E) and $330,209,957 for our Missouri jurisdiction (Column F).

Q. I DIRECT YOUR ATTENTION TO SECTION G, SCHEDULE 1 THROUGH SCHEDULE 3. PLEASE EXPLAIN THEM.

A. Section G, Schedule 1 computes test year amounts of materials and supplies using a 13-month average. Prepayments are also calculated based on a 13-month average.

Section G. Schedule 2 computes projected cash working capital for the twelve months ended December 31, 2003. The expense and revenue lag for each component is the same as used by the Staff in ER-2002-424. The computation, using updated normalized test year expenses, results in a cash working capital requirement of ($494.303). Cash working capital is a rate base deduction due to the increase in property taxes.

Section G. Schedule 3 and Schedule 4. calculate the Company's income tax gross-up factor as well as lags for income taxes and interest expense. In addition. the calculations are shown for interest and income tax offset.

Q. WILL YOU PLEASE DESCRIBE SECTION H, SCHEDULE 1?

A. Section H, Schedule 1 summarizes the capital structure of the Company as of December 31, 2003 and an adjusted capital structure using 49.81% equity and 43.89% long-term debt. This is the ratio discussed by Empire witnesses Dr. Donald A. Murray and Dr. James A. Vander Weide in their direct testimonies. The return on common equity was set at 11.65% which was derived from the 11.3 % proposed by Empire witness Dr. James H. Vander Weide and the 12.0 % proposed by Empire witness Dr. Donald A Murray. Empire has chosen the midpoint of 11.65 %. Based on an 11.65% return on equity, the Company's return on rate base is 9.54 %.

Q. WILL YOU PLEASE DESCRIBE SECTION H, SCHEDULE 2?

A. Section H, Schedule 2 lists the Company's trust preferred stock series, which was issued March 1, 2001.

Q. WILL YOU PLEASE EXPLAIN SECTION H, SCHEDULE 3?

A. Section H, Schedule 3 lists each series of the Company's first mortgage bonds outstanding along with any associated unamortized expense, discount and premium at December 31, 2003 in columns A and B. Columns C and D reflect the first mortgage bonds that would be necessary to meet the adjusted capital structure as reflected in Section H, Schedule 1. No adjustments to long term debt have been made in this case.

Q. WHAT IS CONTAINED IN SECTION H, SCHEDULE 8?

A. Section H, Schedule 8, details Empire's capital structure for first mortgage bonds and trust preferred. It shows an embedded rate of 7.25% for first mortgage bonds. The rate for the trust preferred series is 8.93%.

Q. PLEASE ELABORATE ON SECTION J. SCHEDULE 1.

A. Section J. Schedule 1 is a test year income statement with adjustments to normalize test year electric operations. Column A reflects total Company results for the twelve months ending December 31, 2003. Column B summarizes adjustments to total Company electric operations. Column C is the total Company pro forma income statement. Column D reflects Missouri jurisdictional results for twelve months ending December 31, 2003. Column E shows the projected portion of adjustments for Missouri jurisdictional electric operating statement, and Column F summarizes the pro forma income statement applicable to Missouri.

Q. PLEASE DISCUSS SECTION J, SCHEDULE 2.

A. Section J, Schedule 2 details the following adjustments to electric operations test year amounts as shown on Section J, Schedule 1:

Total Company and Missouri revenues are adjusted to reflect customer numbers at December 31, 2003, to normalize weather for the test year, and to exclude revenues for one large industrial customer who has recently discontinued operations. The customer growth adjustment annualizes the revenues to reflect what would have been received if the year-end level of customers had been served by the Company for the entire test year. The differences in December 31, 2003 customers and the customers billed in each month of the test year were multiplied by the average kilowatt-hours ("Kwh") per customer in that month. The change in Kwh was multiplied by the average cost per Kwh to obtain the revenue adjustment. In these calculations, the Kwh and the average charges reflect the effect of unbilled revenues adjustments which are made to match revenues to generation and fuel expense.

Q. PLEASE DESCRIBE THE PROCEDURE USED IN CALCULATING THE ADJUSTMENT FOR WEATHER.

A. Empire used the Electric Power Research Institute ("EPRI") Hourly Electric Load Model ("HELM") to calculate the weather adjustment to class usage. This was the model used by the Staff of the Commission ("Staff") in prior cases. HELM used hourly load data by class to estimate the response to daily weather for each weather sensitive class. Weather normalized usage by class is then calculated for each month to determine normal weather variables based on estimated response. The weather variables are then matched to the actual usage over the corresponding time period that the usage was recorded. The weather adjustment is then calculated for each class by taking the difference between the normalized usage and actual recorded usage.

Q. PLEASE EXPLAIN THE INPUTS TO THE MODEL.

A. The four data inputs to the model include monthly class usage, hourly class load data, actual daily weather variables, and normal daily weather variables. National Oceanic and Atmospheric Administration ("NOAA") weather for Springfield, Missouri weather station was used to obtain the actual and normal daily weather variables.

Q. WHAT CUSTOMER GROUPS WERE EVALUATED?

A. The residential customer class, the commercial groups of commercial CB, commercial SH, and commercial TEB and industrial GP group were included in the weather normalization. The other customer groups and rates are not significantly weather sensitive and were not included.

Q. HOW WERE THE REVENUE ADJUSTMENTS DUE TO WEATHER CALCULATED?

A. The appropriate rate schedule average price of electricity for each month in the time period was applied to the Kwh adjustments to derive revenue adjustments. The sum of the monthly revenue adjustments was the test year revenue adjustment for that customer group.

Q. WOULD YOU EXPLAIN THE ADJUSTMENTS TO EXPENSES?

A. Total Company production costs have been increased by $19,815,396 and $16,341,665 for the Missouri jurisdiction. Included in this total is an increase of $1,008,204 total Company or $830,947 for the Missouri jurisdiction reflecting normalized operation and maintenance ("O&M") expenses sponsored by Empire witness Blake Mertens. Also included is an increase of $503,874 total Company and $415,285 for Missouri jurisdiction, which reflects the annualized payroll expense for the test year. Payroll expense reflects the wages at December 31, 2003 adjusted for known changes and positions that are currently authorized but unfilled. Capacity charges decreased by $2,281,671 for the Missouri jurisdiction. Fuel and purchased power costs were normalized, as of December 31, 2003 to reflect customer growth and weather. This resulted in an increase of $21,083,985 on a total Company basis or $17,377,104 for the Missouri jurisdiction (see direct testimony of Company witnesses Brad Beecher and Jill Tietjen).

Transmission expenses were increased by $43,392 for the Missouri jurisdiction to reflect annualized payroll costs.

Distribution expenses were increased by $276,216 to adjust for the same costs as mentioned for transmission expenses.

Customer accounts, customer assistance and sales expense were increased by $143,419, $35,552, and $12,070 respectively to recognize increased payroll costs.

Administration and general expenses were increased by $560,958 for the Missouri jurisdiction. Of the total, $320,375 was for increased payroll and 401(k) costs. The annualization of FAS 87 and 106 costs resulted in a decrease in the amount of $1,118,765. The method used to calculate the adjustment for FAS 87 and 106 is discussed in the Company witness C. Kenneth Vogl. Common stock expenses were amortized over three years resulting in an increase of $1,109,348. Rate case expense was increased by $250,000 based on a three year amortization.

Depreciation expense was increased by $28,036,084 and $24,025,489 for the total Company and the Missouri jurisdiction, respectively. The increase incorporates the results of the depreciation study conducted by Empire witness Donald S. Roff.

Q. PLEASE CONTINUE WITH YOUR DESCRIPTION OF SECTION J, SCHEDULE 2.

A. Taxes other than income taxes are increased by $1,682,690 for the total Company or $1,429,337 for the Missouri jurisdiction in order to annualize property taxes to the plant in service at December 31, 2003, and to include payroll taxes from the annualized payroll expenses.

The next five adjustments are a result of the changes that were made above and also to adjust book taxes to taxes calculated on a regulatory basis.

The last adjustment, interest on customer deposits, is made to move the amount from below the line to above, which is consistent with past Staff adjustments.

Q. IN SOME INSTANCES, THE AMOUNT FOR THE MISSOURI JURISDICTION AND TOTAL COMPANY ARE THE SAME; WOULD YOU PLEASE EXPLAIN?

A. Some of the adjustments are calculated for the Missouri jurisdiction only, which is why some of the adjustments are the same. For example, rate case expense was calculated for the Missouri jurisdiction only.

Q. WILL YOU PLEASE DESCRIBE SECTION K, SCHEDULE 1?

A. Section K, Schedule 1, Column A lists, by plant account number, the currently effective depreciation rates. Columns B and C show the total Company and Missouri jurisdictional test year depreciation accruals.

Q. PLEASE DESCRIBE SECTION K, SCHEDULE 2.

A. Section K, Schedule 2 is a listing of Empire's normalized depreciation electric plant in service at December 31, 2003. Column D represents the proposed depreciation rates for each category (see direct testimony of Company witness Donald S. Roff).

Page 4 of Section K, Schedule 2 is a summary of the depreciation accruals and expense adjustments. It shows the proposed depreciation expense adjustment of a $24,025,489 for the Missouri jurisdiction.

Q. WILL YOU DESCRIBE SECTION L, SCHEDULE 1?

A. Section L, Schedule 1 is a statement of taxes charged to electric operations with pro forma adjustments during the test year.

Q. PLEASE EXPLAIN SECTION L SCHEDULE 2.

A. This schedule starts with net income. Income taxes to adjust net operating income before income taxes are then added back. From this point, the income is adjusted to take into account various additions and deductions from income to arrive at taxable income.

Q. WILL YOU TELL US WHAT SECTION L, SCHEDULE 2, PAGE 1 SHOWS?

A. Section L, Schedule 2 shows the calculation of federal and Missouri income taxes payable for the twelve months ending December 31, 2003. Lines 24 and 28 (Column D) include the current portion of total federal and Missouri state income taxes charged to electric operations for determining the rate of return.

Q. WILL YOU TELL US WHAT SECTION L, SCHEDULE 2, PAGE 2 SHOWS?

A. This schedule is a calculation of provision for income taxes payable for determining the rate of return.

Q. PLEASE ELABORATE ON SECTION M, SCHEDULE 1, ALLOCATIONS.

A. Section M, Schedule 1 is a narrative description of Empire's allocation procedure to the states we serve and the reasons why it is used. It explains what allocations are necessary and defines the bases used for allocating rate base, revenue and expense.

Q. WHAT METHOD WAS USED TO DERIVE EMPIRE'S DEMAND ALLOCATION FACTORS FOR JURISDICTIONAL ALLOCATIONS?

A. The average of twelve monthly coincident peak demands by jurisdiction was used to jurisdictionally allocate production and transmission costs.

Q. WHY HAS THE COMPANY ELECTED TO USE THIS METHOD FOR JURISDICTIONAL ALLOCATIONS?

A. During prior rate proceedings as well as our last electric rate proceeding, the Commission accepted the use of the average monthly coincident peaks for jurisdictional allocations. Additionally, this method was used by our other four jurisdictions for jurisdictional allocations. The Company desires to keep the jurisdictional allocations consistent between our service territories to ensure full allocation of production and transmission costs.

Q. PLEASE DESCRIBE THE AVERAGE OF TWELVE MONTHLY COINCIDENT PEAK DEMAND ALLOCATION METHOD.

A: The monthly coincident peak (CP) demands for the test year are determined for the following jurisdictions: (a) Missouri wholesale; (b) Kansas wholesale; (c) Missouri retail; (d) Kansas retail; (e) Oklahoma retail; and (f) Arkansas retail. An average of the monthly CP demands is calculated for each of the above jurisdictions. These average monthly CP demands are then used to allocate production and transmission costs to each of the Company's jurisdictions, see Section N Schedule 1 attached to this testimony.

Q. HOW WERE THE MONTHLY COINCIDENT DEMANDS BY JURISDICTION OBTAINED?

A. In 1980, the Company installed metering at points where transmission and distribution lines crossed state boundaries. The demand readings at the time of monthly system peak for each of the metering points are combined with generation and tie line data to calculate the jurisdictional demands.

Q. WILL YOU DESCRIBE SECTION M, SCHEDULE 2, CONSISTING OF EIGHT

PAGES?

A. Empire operates as an integrated Company in contiguous areas of Kansas, Missouri, Oklahoma and Arkansas. With very few exceptions, the Company's operations and costs are uniform throughout its service area and allocations of property and expenses are made only for the purpose of presenting the results of operations by individual state. These allocations are consistent with prior rate cases filed by the Company.

Section M, Schedule 2 shows the many components of rate base, revenue and expense as they are allocated to the various ratemaking jurisdictions under which we operate. The dollar amounts and percentages applicable to each jurisdiction are shown for each item, as well as a reference to the item number in this schedule that serves as the basis for allocation of the total Company dollar amount. Such allocations are necessary for a determination of net electric operating revenue by states in order to derive a rate of return on rate base for each state.

IV. Load Research Study

Q. HAS THE COMPANY CONDUCTED A LOAD RESEARCH STUDY FOR THIS PROCEEDING?

A. Yes, the Company conducted a load research study utilizing data from the twelve-month time period of October 2002 through September 2003.

Q. PLEASE DESCRIBE THE LOAD RESEARCH STUDY.

A. The Company has been performing load research studies since 1977. Meters were installed and data collected for all jurisdictions in 1978, 1981, 1985, 1990, March 1994 and for the period stated above. Standard stratified random sampling techniques were used for selecting the samples. The sample covered all rate groups in residential, commercial, and industrial categories. Lighting rates were not sampled. The basic analysis of this data provided daily load profiles in addition to rate group coincident and non-coincident demand.

V. Loss Study

Q. HAS THE COMPANY CONDUCTED A STUDY TO DETERMINE LOSS PERCENTAGES AT THE VARIOUS VOLTAGE LEVELS?

A. Yes, the Company conducted a loss study for the load research period of January 2002 through December 2002. This loss study derived losses for the following service levels: (a) transmission/substation load and no-load; (b) distribution primary load and no-load; and (c) distribution secondary load and no-load.

Q. WHY IS IT NECESSARY TO CALCULATE LOSS PERCENTAGES AT THE VARIOUS VOLTAGE LEVELS?

A. The load research data is recorded at the customer's consumption voltage level. Because of losses, the amount of power generated is greater than the amount of power consumed. Since losses vary by voltage level, consumption by a customer taking secondary service would require production of more power than a customer taking service at a higher voltage level (i.e., transmission). To fairly allocate costs to customer classes, it is necessary to measure the amount of power that must be generated to meet the demands of each class. Demand and energy allocators then must be adjusted to account for losses in order to allocate production plant and energy properly. Similar adjustments must be made for transmission and distribution allocators.

Q. PLEASE DESCRIBE THE USE OF THE CALCULATIONS DERIVED FROM THE COMPANY'S LOSS STUDY.

A. The losses derived from the Company's loss study were allocated to load research hourly loads by voltage level and then allocated to rate. The Company's Kwh losses by class are shown in Section N Schedule 3.

VI. Analysis in Preparation of Cost of Service

Q. WHAT TEST YEAR IS USED FOR THE PURPOSES OF COST OF SERVICE?

A. The test year is the twelve months ending December 31, 2003.

Q. IN PREPARATION FOR THE COMPANY'S COST OF SERVICE STUDY, WERE DEMANDS BY RATE GROUP CALCULATED?

A. Yes. Certain items of rate base and expenses in the cost of service study that are considered to be demand related need to be allocated to rate. These costs are allocated to rate, based on the Company's calculated demands by rate group.

Q. HOW WERE THESE DEMANDS BY RATE GROUP CALCULATED?

A. The basic data on energy consumption, coincident demand, and non-coincident demand was provided by the Company's load research. The above load research data was combined with the demand loss information obtained in the Company's loss study to provide coincident demand by rate group at the generation level. This load research data is shown in Section N Schedules 3 - 6.

VII. Cost of Service

Q. WHAT IS THE PURPOSE OF AN EMBEDDED COST OF SERVICE STUDY?

A. An embedded cost of service study apportions the Company's revenue requirement (or cost of service) among the various service classifications (rate groups) on the basis of a service classification's use of capacity, energy, and customer-related facilities.

Q. IS THERE A SPECIFIC PROCEDURE OR APPROACH THAT MUST BE FOLLOWED IN PREPARING AN EMBEDDED COST OF SERVICE STUDY?

A. No. Embedded cost of service studies can take a wide variety of forms and utilize numerous different techniques and procedures. However, regardless of the form or procedure followed, embedded cost studies usually utilize a standard three-step approach of functionalization, classification, and allocation.

Q. PLEASE DESCRIBE THE FUNCTIONALIZATION PROCESS.

A. The functionalization process groups Company investment and expenses into the major operating categories of production, transmission, distribution, and administrative and general ("A&G"). Much of the functionalization has been accomplished through the Federal Energy Regulatory Commission ("FERC") system of accounts. Some accounts, however, are related to all three functions.

The functionalization step is important in the cost of service process to insure that allocations to customer groups can be properly made. Each function may be allocated on a different basis. If certain costs are not functionalized, it may be difficult to assign the costs to the correct customers.

Q. PLEASE DISCUSS THE CLASSIFICATION PROCESS.

A. Once functional areas have been determined and grouped, all costs are classified prior to the allocation process. For electric operations, classification categories include: (1)

demand-(or capacity) related, which relates to the cost of providing for the maximum hourly usage of a customer; (2) energy-related, which relates to consumption over a period of time; and (3) customer-related, which relates to the costs of serving a customer even if no consumption occurs.

The classification step shows the nature of the costs and how each cost should be allocated. The cost causation determines the type of allocator to be used, whether related to the number of customers, the demand level, or the energy consumed.

Q. PLEASE DESCRIBE THE ALLOCATION PROCESS.

A. Allocation is the process whereby the functionalized and classified totals for all operating expenses and rate base investments are assigned to customer rate groups, based on a variety of specific and non-specific allocation factors related directly to the cost causation. The results of this final step show the cost of serving each customer rate group. Some costs are directly assignable to certain customer groups. The remainder must be allocated based on knowledge of the characteristics of each customer rate group. The load research, losses, and demands described above provide part of the rate group characteristics that need to be known for allocation of costs.

Q. WAS THIS THREE-STEP PROCESS FOLLOWED IN PERFORMING THE COST OF SERVICE STUDY FOR THIS CASE?

A. Yes.

Q. FOR THE FIRST STEP, FUNCTIONALIZATION, WHAT ACCOUNT BALANCES WERE REFUNCTIONALIZED?

A. The general plant, administrative and general expenses, and working capital were refunctionalized.

The general plant in service and depreciation on general plant was functionalized on the basis of net production, transmission and distribution plant in service. Functionalized net general plant is shown on page 5 of the Company's Cost of Service Study. (Section N Schedule 1)

General plant depreciation expense was not functionalized but was later allocated to the customer classes on the basis of gross production, transmission and distribution plant labor ratios.

A&G expenses were functionalized on the basis of either net plant in service, or on the labor component of operation and maintenance expenses, depending upon the nature of the A&G expense being analyzed. The labor study used to perform this functionalization is based on analyses of the labor component of each FERC account (excluding A&G).

Q. PLEASE DESCRIBE THE DIFFERENCE BETWEEN THE ADMINISTRATIVE AND GENERAL EXPENSES THAT WERE FUNCTIONALIZED ON THE BASIS OF NET PLANT AND THOSE THAT WERE FUNCTIONALIZED ON THE BASIS OF LABOR.

A. Most of the A&G accounts are labor related, i.e., they relate to salaries, office supplies and expenses, the cost of outside services, and pensions and benefits. Accordingly, these items have been functionalized on the basis of the functionalized labor components of operation and maintenance expenses.

Plant related A&G expenses are Accounts 924 and 928, property insurance and regulatory commission expense, respectively. These expenses are incurred in proportion to the value of plant in service and have therefore been functionalized according to the net plant in service balances.

Q. PLEASE EXPLAIN HOW WORKING CAPITAL WAS FUNCTIONALIZED.

A. All cash working capital requirements were functionalized based on the total expenses. Functionalized cash working capital is shown in Section N Schedule 1, page 6.

Material and supply balances are drawn upon by utility personnel to operate and maintain utility plant. All materials and supplies are accounted for by function, with transmission and distribution supplies split on transmission and distribution ("T&D") labor.

Prepayments relate primarily to advanced payments on insurance. Most prepayments are accounted for by function with the rest being functionalized using labor ratios.

Q. WHERE ARE THE FUNCTIONALIZED COMPONENTS OF WORKING CAPITAL SHOWN?

A. They are shown in Section N Schedule 1, page 6.

Q. WOULD YOU NOW DESCRIBE THE CLASSIFICATION PHASE?

A. Generally, all production plant has been classified as demand-related since it is sized primarily to meet system peaks. Transmission plant has been classified as demand since it is generally sized to transmit power associated with system peak demands. Distribution plant has been classified as being demand and customer related since some costs of the distribution system are associated with both the number of customers and the maximum hourly usage of those customers. The installation of service drops and meters are a part of the customer component. Investment in these customer components of plant is necessary simply to hook up a customer, whether or not the customer uses any electricity. Classification by component is shown in Section N Schedule 1, page 3.

Q. HOW WERE DISTRIBUTION PLANT ACCOUNTS CLASSIFIED?

A. First, an analysis of each distribution account to assign costs to functional groups was conducted. Each functionalized distribution account was then classified as either being demand-related, customer-related, or both.

Q. WHICH DISTRIBUTION PLANT ACCOUNTS WERE CLASSIFIED AS DEMAND-RELATED?

A. The accounts that are considered to be entirely demand-related are: Land and Land Rights, Account 360; Structures and Improvements, Account 361; and Substations, Account 362.

Q. WHICH DISTRIBUTION PLANT ACCOUNTS WERE CLASSIFIED AS CUSTOMER-RELATED?

A. The accounts considered to be completely customer-related are: Services, Account 369; Meters, Account 370; Installations on Customer's Premises, Account 371; and Street Lighting and Signal Systems, Account 373.

Q. WHICH DISTRIBUTION PLANT ACCOUNTS WERE CLASSIFIED AS BEING BOTH DEMAND AND CUSTOMER-RELATED?

A. These accounts were classified as being both demand and customer-related: Poles, Towers, and Fixtures, Account 364; Overhead Conductors, Account 365; Underground Conduit, Account 366; Underground Conductors, Account 367; and Line Transformers, Account 368.

Q. HOW WERE ACCOUNTS 364 THROUGH 368 SPLIT BETWEEN CUSTOMER AND DEMAND?

A. For this case, the customer/demand split for these accounts is based on an analysis performed by the Commission Staff and Empire. The results of this analysis are shown in Section N Schedule 5.

Q. HOW WERE EXPENSES AND OTHER COSTS OF SERVICE CLASSIFIED?

A. Expenses were classified according to the classifications of the plant items with which they are associated. Customer service information and sales expenses were all classified as customer-related.

The classification of most expenses and rate base items is accomplished through the classification and allocation of related plant balances.

Q. PLEASE DISCUSS THE ALLOCATION PHASE.

A. The objective of the allocation phase is to allocate system costs to the various customer classes in proportion to each class's responsibility for those costs. This requires the selection of allocation factors that reflect both the operating and design characteristics of the system and the manner in which customers use the system.

Q. WHAT ALLOCATION METHOD WAS USED FOR DEMAND-RELATED PLANT AND EXPENSES?

A. An average and excess allocation method was used. Empire is a summer peaking system with an annual load factor of approximately 55%. The winter peak is approximately 80-90% of the summer peak. Empire's generation design and planning is oriented largely toward meeting summertime peaks. This means that customers who use the production facilities on peak should bear a cost responsibility proportional to their demands on peak. The Company also plans for maintenance capacity and also considers the duration of loads in deciding the types of plant it needs to meet its loads throughout the year in the most economic fashion.

Q. WHAT ELSE DOES THE AVERAGE AND EXCESS METHODOLOGY ACCOMPLISH?

A. It allocates a portion of plant according to peak and a portion according to energy or load duration.

Q. HOW WERE THE AVERAGE AND EXCESS FACTORS FOR EACH CLASS COMPUTED?

A. The average demand is the monthly energy divided by the number of hours in the month. The excess demand is the twelve month average non-coincident peak demand less the average demand. The average and excess allocator is calculated by multiplying the average demand by the system load factor and summing this with the excess demand times one minus the load factor.

Q. HOW WERE PRODUCTION RELATED ENERGY COSTS ALLOCATED?

A. They were allocated on the basis of each customer rate group's kilowatt-hour use, expressed at the generation level.

Q. HOW WERE TRANSMISSION PLANT COSTS ALLOCATED?

A. All the transmission plant is demand related, being allocated on average and excess demand. Transmission operation and maintenance expenses were allocated on the same basis as plant.

Q. HOW WERE DISTRIBUTION COSTS ALLOCATED?

A. All direct assignments were made before allocations were performed. The demand components of distribution costs were allocated on the basis of each customer classification's maximum diversified non-coincident demand. Distribution systems are designed to meet more localized and customer class related peak requirements, whereas production and transmission systems are designed to meet system-wide peak requirements. Consequently, the demand allocation factor used for the distribution system must give weight to customer class demands regardless of the time they occur. The non-coincident demand allocation factor provides this weighting. The customer component of distribution costs was allocated based on a weighted number of customers.

All customer-related costs have been allocated on the basis of the number of customers within each class, special studies, or a direct assignment.

Q. WHAT SPECIAL STUDIES WERE USED IN ALLOCATING CUSTOMER COSTS?

A. With respect to the allocation factors used to allocate plant, previous studies were used to: (1) weight the number of customers in each class to reflect the relative costs of service drops within each class for allocating Account 369 - Services (CUST SERV);

(2) estimate the investment in meters by type and class in order to allocate Account 370 - Meters (WTD MET INV); and (3) specifically assign costs to the customer classes based upon a detailed review of Account 371 - Installations on Customer Premises.

With regard to customer expenses, studies were updated for: (1) assigning uncollectible accounts expenses - Account 904; and (2) allocating customer assistance expenses - Account 908.

Q. IN THE ALLOCATION STEP THERE WERE MANY ALLOCATION FACTORS. WHERE ARE THESE FACTORS SHOWN?

A. The allocation factors and specific assignments are presented on Section N Schedules 2-5. Methods of allocation are summarized in Section N Schedule 6, pages 1 - 3.

Q. WOULD YOU PLEASE SUMMARIZE THE RESULTS OF THE COST OF SERVICE STUDY?

A. Yes. The results without an increase are shown on Section N Schedule 1, page 1. As can be seen, the residential rate groups, which account for approximately 45% of the total Missouri jurisdictional rate revenue, show rate group returns significantly less than the system average return of 4.26%. All the other rate groups are higher than the average. The only power furnace customer has discontinued service as of December, 2003, so no costs are shown for this group.

Q. WHAT ARE THE OVERALL PRICING OBJECTIVES THAT THE COMPANY SEEKS IN THIS PROCEEDING?

A. The Company has the objective of designing rates that provide for a stable recovery of the approved revenue requirement through the use of price signals which encourage the efficient utilization of electricity. These price signals should also recognize the realities of competition in the providing of energy services to our customers. The rate design must send the correct price signal to allow the customer to make cost-effective consumption decisions consistent with the Company's cost of service. The rate design must also satisfy a wide variety of customer needs and the costs associated with meeting these needs.

Q. WHAT HAS GUIDED THE DESIGN OF EMPIRE'S RATES IN THE PAST?

A. Proposals on rate design have been guided by a desire to have equitable and stable rates for all customer classes. The Company has tried to be sensitive to opportunities to increase the utilization of generating units so that fixed costs could be spread over more Kwh, thereby reducing the cost of power to all customers.

VII. Other Recommended Changes

Q. IS THE COMPANY RECOMMENDING OTHER CHANGES TO THE TARIFF SHEETS?

A. The Interim Energy Charge Rider, Rider IEC and a fuel adjustment, Rider FA are discussed in the direct testimony provided by Empire witness Mr. H. Edwin Overcast.

Q. HAS THE COMPANY PROPOSED RATE DESIGN CHANGES OR REVENUE SHIFTS IN THIS CASE?

A. An across the board increase is being proposed in this case, with an equal percentage increase to each rate class. However, rate design is being proposed within some of the rates. These changes are addressed in the direct testimony provided by Empire witness

Ed Overcast.

Q. ARE THERE ADDITIONS OR CHANGES TO THE TARIFF SHEETS?

A. Yes. Changes to the Credit Action Fees, Schedule CA are being proposed in order to bring special service charges more in line with current costs. This was done in the last water case, Case No. WR-2003-0177 and Empire feels electric charges should be at least equivalent.

A new fee is being included on the Other Sales and Services, Schedule OS for a meter treater service offered by Empire. This service is available to customers choosing to purchase surge protection for motor driven electric equipment.

The Company is proposing adding a paragraph to the Large Power Service, Schedule LP tariff sheet explaining that a telephone line must be provided by the customer to retrieve interval metering data for billing and load research purposes and providing the Company priority access to the line between the hours of midnight and 6:00 am each day. If the customer chooses for the Company to provide the telephone line they will be charged $30.00 per month for this service.

Some minor wording changes have been proposed to the rules and regulations for meter installations. These changes serve to clarify the existing rule and to address meter height.

Schedule PL, Private Lighting Service, and Schedule SPL, the Municipal Street Lighting Service has been revised to add the wattage of the light fixtures to the billing information. In addition, the Company is proposing an additional charge to Schedule SPL to include a transformer charge in the additional charges section.

The Promotional Practices, Schedule PRO, is being changed to restate the section dealing with the Employee Purchase Plan. Section A, paragraph 4 has been updated to be consistent with the current employee handbook.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

LIST OF SCHEDULES

Schedule No.	Description
KSW-1	Schedules Supporting Revenue Requirement

INDEX TO KSW-1

Section No.	Schedule No.	Description
C	1	Comparative and Summary Information
D	1	Rate Base and Rate of Return
E	1	Electric Plant in Service by Primary Account
F	1	Accumulated Provision for Depreciation
G	1	Working Capital
G	2	Cash Working Capital
G	3	Income Tax and Interest Expense Factors
H	1	Capital Structure at December 31, 2003
H	2	Preferred Stock
H	3	Long-Term Debt
H	8	Capital Costs and Structure
J	1	Test Year Operating Income Statements
J	2	Test Year Adjustments
K	1	Depreciation Rates and Accruals
K	2	Normalized Depreciation Expense
L	1	Taxes Charged to Electric Operations
L	2	Income Tax Calculation
M	1	Bases of Allocation
M	2	Allocation of Rate Base Items
N	1-6	Cost of Service