MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

COST OF SERVICE

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2008-0093

Jefferson City, Missouri
February 22, 2008

COST OF SERVICE REPORT

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I. Executive Summary

The Staff has conducted a review in Case No. ER-2008-0093 of all cost of service components (capital structure and return on rate base, rate base, depreciation expense and operating expenses) which comprise The Empire District Electric Company's (Empire's, EDE's, or Company's) Missouri jurisdictional revenue requirement. This audit was in response to Empire's application to increase its Missouri jurisdictional retail rates in the amount of \$34,725,203, filed on October 1, 2007.

The Staff's recommended increase in revenue requirement is based upon a test year of the twelve months ending June 30, 2007, with a test year update period ending December 31, 2007. Major elements of the revenue requirement calculation for Empire were measured through December 31, 2007, in the Staff's case. The Staff's recommended revenue requirement for Empire at the midpoint of its return on equity range (ROE) of 9.98% is approximately \$10,341,598.

Impact of Staff's Revenue Requirement on Each Retail Rate Customer Class

The impact of the Staff's recommended revenue requirement for each retail rate customer class will be proposed in the Staff's rate design testimony that is to be filed on March 7, 2008.

II. Background of Empire

Empire is a Kansas corporation providing electrical utility services in Missouri, Kansas, Arkansas and Oklahoma. Empire also provides water utility services and operates a natural gas distribution business, both in Missouri. Empire serves approximately 166,000 retail electric customers throughout its system of which 146,000 are Missouri customers.

In 2006, the Missouri Public Service Commission (Commission) approved Empire's acquisition of the Missouri natural gas distribution operations of Aquila, Inc. (Aquila). The gas distribution business is operated by Empire through its wholly owned subsidiary, The Empire District Gas Company.

Empire also provides non-regulated business services. These services, which are offered through Empire's wholly-owned subsidiary EDE Holdings, Inc., include leasing of fiber optics cable and equipment, provision of internet access and other operations.

Empire last sought to change its Missouri jurisdictional electric retail rates in Case No. ER-2006-0315. In its Order dated December 20, 2006 in that proceeding, the Commission granted Empire a total increase in rates of $29,369,397. Of that amount, $18,900,169 was granted through a traditional revenue requirement approach, with the remaining $10,469,228 awarded in the form of a "regulatory plan amortization." These amortizations will be described in more detail later in this Cost of Service Report (Report).

III. Test Year/Update Period

Though Empire filed its case based upon a June 30, 2007, test year, it made adjustments to its case to reflect the impact of several material events it expected to occur in the last six months of 2007. The Staff, in its filing "Staff Recommendation Regarding Test Year and True-Up," dated October 31, 2007, agreed with Empire's proposed test year of the twelve months ended June 30, 2007, and in addition proposed a test year update period in this case for the six months ending December 31, 2007. The Staff did not propose a true-up audit in this proceeding. The Commission accepted the Staff's recommended test year and test year update period recommendations in its "Order Accepting Test Year and True-Up and Adopting Procedural Schedule," dated November 16, 2007, stating in part as follows on page 2:

> . . . Empire initially requested that the Commission order that the test year data be updated utilizing a true-up audit with an ending date of December 31, 2007. In its response, Staff argued that a true-up audit should not be necessary in this case because Staff's and other non-Empire parties' direct testimony filings will reflect all material events affecting Empire's revenue requirement through December 31, 2007. Accordingly, Staff proposed utilizing the test year ending June 30, 2007, with a test year update period ending December 31, 2007. Staff further noted that it does not believe a true-up will be necessary in this case if its test year and update recommendation is adopted.
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> . . .
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> At the November 5, 2007, prehearing conference every party, including Empire, stated that they support the update recommendation proposed by Staff. The Commission finds the update recommendation proposed by Staff, and supported by all parties, to be reasonable and it shall be adopted in this case. . . .

The purpose of a test year update period is to establish a cut-off point to which major elements of a utility's revenue requirement are to be updated beyond the test year for inclusion in the Staff's and other parties' direct cases. In contrast, a true-up is a re-audit and update of major elements of a utility's revenue requirement beyond the end of the ordered test year and test year update period. When ordered, true-ups involve the filing of additional sets of testimony and the scheduling of additional evidentiary hearings ordered by the Commission. While test year update periods are ordered by the Commission in almost all general rate proceedings, true-ups are used on a selective basis only.

The rate items updated through the end of the update period by the Staff included plant in service; depreciation reserve; other rate base components; payroll expense; payroll-related benefits; fuel and purchased power costs; and the customer growth annualization for revenues.

One item included in the Company's case beyond the test year was the projected rate base addition in November or December 2007 of the Asbury Generating Unit Selective Catalytic Reduction (SCR) equipment. Due to certain mechanical problems with the Asbury unit during its extended outage in the fall of 2007, the Asbury SCR addition was not in-service as of December 31, 2007, and in fact has still not been declared to be in-service by the Staff as of the date of this report. Since Empire agreed and the Commission's Order dated November 16, 2007, established the end of calendar year 2007 to be the cut-off for inclusion of known and measurable items in Empire's revenue requirement, the Staff's case does not reflect any rate base or income statement impacts of the Asbury SCR project. Assuming the Asbury SCR is in service by the operation-of-law date of this case, the Staff's case still will not reflect the Asbury SCR in service. Even if a true-up period ending December 31, 2007, as Empire originally proposed, had been agreed upon by the parties and accepted by the Commission, the Asbury SCR was not in service by December 31, 2007, and still not in service.

Please note that it is only the specific Asbury SCR addition, and its associated expenses, that are not reflected in the Staff's case. The Company's Asbury Station has been generating electricity for Empire for many years, and the costs of its non-SCR investment has been included in the Staff's rate base, and its non-SCR related operating costs included in the Staff's income statement, as in many previous cases.

The Company incurred material expenses associated with an ice storm that affected its service territory in December 2007. Empire has indicated that it will seek recovery of costs of the December 2007 ice storm in future rate proceedings. Accordingly, the Staff has not adjusted Empire's test year to include any of these costs in its case.

IV. Major Issues

The following are the major issues that exist between the Staff and the Company as a result of their respective direct filings. These issues are discussed here because of their estimated dollar value. A brief explanation for each issue follows, with an estimate of its dollar value:

Return on Equity (ROE) – Issue Value – ($10 million). The Staff has recommended a 9.98% ROE at the midpoint. Empire is recommending an 11.6 % ROE. This issue is addressed in detail in the Section V of this Report.

Asbury SCR Costs – Issue Value – ($6 million). As previously discussed, Empire included in its direct case the estimated rate base and income statement impacts of the Asbury SCR plant addition, originally scheduled for November 2007. As this additional plant investment was not in-service as of December 31, 2007, the end of the Commission's order test year update period in this case, the Staff has not included the financial impacts of this project in its direct filing.

Unamortized Ice Storm Costs – Issue Value – ($1.4 million). Empire has proposed to include the unamortized portion of its January 2007 ice storm deferral in its rate base. In accordance with past Commission precedent, the Staff is excluding this amount from its rate base, while allowing an amortization of these costs over five years.

Depreciation Rates – Issue Value – ($1.4 million). The Company has proposed new depreciation rates in this proceeding. The Staff recommends no change to Empire's currently authorized depreciation rates, as the Staff contends any change to depreciation rates would be redundant as long as Empire is operating under its Regulatory Plan, which includes the opportunity by the Company to receive additional rate allowances through the regulatory plan amortization calculation.

Off-System Sales – Issue Value – ($950,000). The Company's direct case is premised upon use of a five-year average of off-system sales (OSS) margins to impute into revenues. The Staff recommends using an OSS imputation based upon its achieved margins in the first six months of 2007.

Incentive Compensation – Issue Value ($900,000). The Staff has recommended a disallowance of incentive compensation paid Empire employees, including executive management, related to an earnings per share (EPS) goals and discretionary bonuses which are unsupported by any well defined goals with tangible benefits to ratepayers. Staff's position is consistent with the Commission's decision on this issue in Empire's recent rate case, Case No. ER-2006-0315.

Prepaid Pension Asset (PPA) – Issue Value ($2.5 million). The Company's PPA balance in ratebase includes regulatory assets associated with implementation of Financial Accounting Standard No. 158 (FAS 158). The Staff's rate base amount for the PPA does not include FAS 158 assets.

There are various other issues between the Staff and the Company based upon their respective direct filings which are of lower dollar magnitude. These issues are discussed as well in this Report.

Staff Expert: Mark L. Oligschlaeger, Sections I, II, III and IV

V. Rate of Return

A. Summary

The Financial Analysis Staff (Matthew J. Barnes) recommends that the Commission authorize an overall rate of return (ROR) of 8.22 percent to 8.80 percent for The Empire District Electric Company (Empire or Company). This rate-of-return recommendation is based on a recommended return on common equity of 9.40 percent to 10.55 percent applied to Empire's December 31, 2007, common equity ratio of 50.82 percent. The recommendation is driven by my comparable company analysis using the discounted cash flow (DCF) model. The Staff continues to believe that the DCF model is the most reliable model available for estimating a utility company's cost of common equity. The Staff's midpoint ROE recommendation is 9.98%.

The Staff's embedded cost of long-term debt of 6.80 percent is based on Empire's embedded cost of long-term debt rate provided in response to Staff Data Request No. 0112.

The Staff used Empire's actual consolidated capital structure, which includes all of Empire's operations, as of December 31, 2007, as the basis for its capital structure recommendation. The Staff's resulting capital structure consists of 50.82 percent common equity, 4.58 percent preferred stock, and 44.61 percent long-term debt. Schedule 9 presents Empire's capital structure and associated capital ratios.

The Staff has prepared five attachments and 21 schedules that support its findings and recommendations in the cost of capital area. The attachments contain explanations of various topics important to an understanding of utility cost of capital determinations, in more detail then are addressed within the main body of this Report. The schedules present numerical support for the Staff's rate of return and cost of capital determinations, and are numbered as Schedules 1 through 21. All five attachments and 21 schedules can be found within Appendix 2 of this Report, with the schedules appearing first.

B. Legal Principles of Rate of Return

The *Bluefield Water Works and Improvement Company* (1923) *(Bluefield)* and the *Hope Natural Gas Company* (1944) (*Hope*) cases have been cited as the two most influential cases for the legal framework to determine a fair and reasonable rate of return. In the Bluefield case the Supreme Court ruled that a fair return would be:

1. A return "generally being made at the same time" in that "general part of the country;"
2. A return achieved by other companies with "corresponding risks and uncertainties;" and
3. A return "sufficient to assure confidence in the financial soundness of the utility."

The Court specifically stated:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

In the *Hope* case, the Court stated that:

> The rate-making process . . . , i.e., the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interests. Thus we stated . . . that "regulation does not insure that the business shall produce net revenues" . . . it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock . . . . By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.

> That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

The Hope case restates the concept of comparable returns to include those achieved by other enterprises that have "corresponding risks." The Supreme Court also noted in this case that regulation does not guarantee profits to a utility company. Please see Attachment A for more details regarding the use of cost of common equity models to determine a recommended cost of common equity.

C. Economic Conditions

The Federal Reserve (Fed) has been steadily raising the Fed Funds rate by 25 basis points at every Federal Open Market Committee (FOMC) meeting since June 30, 2004. This began after the Fed had kept the Fed Funds Rate at a 46-year low of 1.00 percent for a full year. The Fed raised the Fed Funds Rate seventeen consecutive times to the level of 5.25 percent. On August 17, 2007, the Fed Funds Rate remained at 5.25 percent. On September 18, 2007, the Fed Funds Rate decreased 50 basis points to 4.75 percent. On October 31, 2007, the Fed Funds Rate decreased 25 basis points to 4.50 percent. On December 11, 2007, the Fed Funds Rate decreased 25 basis points to 4.25 percent. On January 22, 2008 the FOMC made an emergency cut of the Fed Funds Rate of 75 basis points to 3.50 percent and on January 30, 2008 the Fed Funds Rate decreased 50 basis points to its current level of 3.00 percent. Please see Schedule 2-1.

A review of Schedules 5-1 through 5-3 shows that average utility bond yields fell to an average annual yield of 5.39 percent during June 2005, which was the lowest yield in the past 26 years. Utility bond yields have since increased to an average annual yield of 6.23 percent in December 2007. Cost of capital changes for utilities are closely reflected in the yields on public utility bonds and yields on Thirty-Year U.S. Treasury Bonds (see Schedules 5-1 and 5-2). Schedule 5-3 shows how closely the Mergent's "Public Utility Bond Yields" have followed the yields of Thirty-Year U.S. Treasury Bonds during the period from 1980 to the present. The average spread for this period between these two composite indices has been 150 basis points, with the spread ranging from a low of 80 basis points to a high of 304 basis points (see attached Schedule 5-4). Although there may be times when utility bond yield changes may lag the yield changes in the Thirty-Year U.S. Treasury Bond, these spread parameters show just how closely correlated utilities' cost of capital is with the level of interest rates on long-term treasuries. For a detailed explanation of historical economic conditions, please see Attachment B. The significance of the current economic conditions to Empire is that yields on public utility bonds and yields on Thirty-year Treasury bonds are low by historical standards. An example of historical standards is the double digit yields for long-term U.S. Government bonds and corporate bonds from the late 1970's to the mid 1980's. A lower interest rate environment means a lower cost of capital and a higher interest rate environment means a higher cost of capital for a utility. The current yields on U.S. Government bonds and corporate bonds are now more normal by historical standards. The Commission should take the lower and more normal yields on U.S. Government and corporate bonds into consideration when authorizing a rate of return for Empire.

D. Economic Projections

See Attachment C for projections on inflation, interest rates and gross domestic product (GDP).

E. Business Operations of Empire

At the time Staff prepared its Cost of Service Report, Empire's 2007 Annual Report was unavailable, therefore; Staff used the Company's 2006 Annual Report. Empire's Form 10K filing with the Securities and Exchange Commission (SEC) for the 2006 calendar year provides a good description of their business operations:

> We operate our businesses as three segments: electric, gas and other. The Empire District Electric Company (EDE), a Kansas corporation organized in 1909, is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of our electric segment, we also provide water service to three towns in Missouri. The Empire District Gas Company (EDG) is our wholly owned subsidiary formed to hold the Missouri Gas assets acquired from Aquila, Inc. on June 1, 2006. It provides natural gas distribution to communities in northwest, north central and west central Missouri. Our other segment includes investments in certain non-regulated businesses, including fiber optics and Internet access. These businesses are held by our wholly-owned subsidiary, EDE Holdings, Inc. In 2006, 93.0% of our gross operating revenues were provided from sales from our electric segment (including 0.4% from the sale of water), 6.1% from our gas segment, and 0.9% from our other segment. The territory served by our electric operations embraces an area of about 10,000 square miles with a population of over

450,000. The service territory is located principally in southwestern Missouri and also includes smaller areas in southeastern Kansas, northeastern Oklahoma and northwestern Arkansas. The principal activities of these areas include light industry, agriculture and tourism. Of our total 2006 retail electric revenues, approximately 87.6% came from Missouri customers, 6.1% from Kansas customers, 3.0% from Oklahoma customers and 3.3% from Arkansas customers.

We supply electric service at retail to 121 incorporated communities and to various unincorporated areas and at wholesale to four municipally owned distribution systems. The largest urban area we serve is the city of Joplin, Missouri, and its immediate vicinity, with a population of approximately 157,000. We operate under franchises having original terms of twenty years or longer in virtually all of the incorporated communities. Approximately 67% of our electric operating revenues in 2006 were derived from incorporated communities with franchises having at least ten years remaining and approximately 2% were derived from incorporated communities in which our franchises have remaining terms of ten years or less. Although our franchises contain no renewal provisions, in recent years we have obtained renewals of all of our expiring electric franchises prior to the expiration dates.

Our electric operating revenues in 2006 were derived as follows: residential 41.7%, commercial 30.1%, industrial 16.9%, wholesale on-system 4.6%, wholesale off-system 3.2% and other 3.5%. Our largest single on-system wholesale customer is the city of Monett, Missouri, which in 2006 accounted for approximately 3% of electric revenues. No single retail customer accounted for more than 2% of electric revenues in 2006. Our gas operations, which we purchased from Aquila, Inc. on June 1, 2006, serve customers in northwest, north central and west central Missouri. The principal utility properties consist of approximately 87 miles of transmission mains and approximately 1,105 miles of distribution mains. We provide natural gas distribution to 44 communities in northwest, north central and west central Missouri and 174 transportation customers. Our gas operating revenues in 2006 were derived as follows: residential 67.6%, commercial 30.2%, industrial 1.5% and other 0.7%. No single retail customer accounted for more than 4% of gas revenues in 2006. The largest urban area we serve is the City of Sedalia with a population of over 20,000. We operate under franchises having original terms of twenty years in virtually all of the incorporated communities. Thirty-one of the franchises have 10 years or more remaining on their term. Although our franchises contain no renewal provisions, since our acquisition, we have obtained renewals of all our expiring gas franchises prior to the expiration dates. Our other segment businesses, which we operate through our wholly-owned subsidiary EDE Holdings, Inc., include leasing of fiber optics cable and equipment (which we are also using in our own operations) and Internet access services. In August 2006, we sold

> our controlling 52% interest in Mid-America Precision Products (MAPP) to other current owners.
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> MAPP specializes in close-tolerance custom manufacturing for the aerospace, electronics, telecommunications and machinery industries. In December 2006, we sold our 100% interest in Conversant, Inc., a software company that markets Customer Watch, an Internet-based customer information system software. See Item 2, "Properties — Other Segment Businesses" for further information about our other segment businesses. On September 21, 2005, we announced that we had entered into an Asset Purchase Agreement pursuant to which we agreed to acquire the Missouri natural gas distribution operations of Aquila, Inc. (Missouri Gas). The base purchase price was $85 million in cash, plus working capital and subject to net plant adjustments. This transaction was subject to the approval of the Missouri Public Service Commission (MPSC). On March 1, 2006, we, Aquila, Inc., the MPSC staff, the Office of the Public Counsel (OPC) and three intervenors filed a unanimous stipulation and agreement with the MPSC, requesting it approve the proposed transaction. On April 18, 2006, the MPSC issued an Order Approving Unanimous Stipulation and Agreement and Granting a Certificate of Public Convenience and Necessity, effective May 1, 2006. We announced the completion of this acquisition on June 1, 2006. The total purchase price paid to Aquila, Inc., including working capital and net plant adjustments of $17.1 million, was $102.1 million, not including acquisition costs. As of December 31, 2006, the $102.1 million has been increased to $102.5 million for additional true-up items. The acquisition was initially financed by $55 million of privately placed 6.82% First Mortgage Bonds due 2036 issued by EDG, and with short-term debt issued by EDE. This short-term debt was repaid with the proceeds of the sale of our common stock on June 21, 2006.

Empire's total operating revenues were $413,453,000 for the 12 months ended December 31, 2006, versus $364,101,000 for the 12 months ended December 31, 2005. These 2006 revenues resulted in an overall net income applicable to common stock of $39,280,000 and earnings per share (EPS) of $1.39 as compared to the 2005 net income applicable to common stock of $23,768,000 and an EPS of $.92. These revenues and net incomes were generated from total assets of $1,315,888,000 at December 31, 2006, and $1,122,030,000 at December 31, 2005. These figures were taken from Empire's Form 10K SEC filing for the 2006 calendar year.

Empire's current Standard & Poor's Corporation's (S&P's) corporate credit rating is "BBB-" with a Stable outlook, which is one notch above non-investment grade; i.e., junk status. S&P's January 14, 2008 Empire District Electric Company's Research Report provides the explanation of their methodology of assigning credit ratings to Empire:

> The ratings on Joplin, Mo.-based utility Empire District Electric Co. reflect a strong business risk profile (business risk profiles are categorized as 'excellent' to 'vulnerable') and an aggressive financial profile that will remain under pressure over the next several years due to a heavy capital spending program that focuses on new generation and environmental compliance. Hence, continued conservative financing and constructive regulatory treatment will be essential to support key financial metrics at levels suitable for current ratings.

Schedules 7 and 8 present historical capital structures and selected financial ratios from 2003 through 2007 for Empire. Empire's consolidated common equity ratio has ranged from a high of 50.82 percent to a low of 46.47 percent from 2003 through 2007. Empire's consolidated company earned ROE for the last five years has ranged from a low of 5.80 percent in 2004 to a high of 8.50 percent in 2006. Empire's consolidated company estimated earned 2007 ROE was 7.00 percent. In a December 28, 2007 report in The Value Line Investment Survey: Ratings & Reports, Value Line estimates that Empire's consolidated company projected ROE will be 8.50 percent for 2008.

Empire's consolidated company historical funds from operations (FFO) interest coverage ratio for the previous five years has ranged from a low of 3.1 times in 2004, to a high of 4.2 times in 2007. Empire's consolidated company September 30, 2007 FFO interest coverage ratio was 4.2 times. Empire's consolidated company FFO to average total debt ratio for the previous five years has ranged from a low of 15 percent in 2006, to a high of 18 percent in 2004. Empire's consolidated company September 30, 2007 FFO to average total debt ratio was 18 percent.

F. Determination of Cost of Capital

A utility's cost of capital is usually determined by evaluating the total dollars of capital for the utility company as of a specific point in time. This total dollar amount is then apportioned into each specific capital component; i.e., common equity, long-term debt, preferred stock and short-term debt. A weighted cost for each capital component is determined by multiplying each capital component ratio by the appropriate embedded cost or by the estimated cost of common equity component. The individual weighted costs are summed to arrive at a total weighted cost of capital. This total weighted average cost of capital (WACC) is synonymous with the fair rate of return for the utility company.

Authorizing a company's WACC as its rate of return is considered a just and reasonable rate of return under normal circumstances. From a financial viewpoint, a company employs different forms of capital to support or fund the assets of the company. Each different form of capital has a cost and these costs are weighted proportionately to fund each dollar invested in the assets. Assuming that the various forms of capital are within a reasonable balance and are costed correctly, the resulting total WACC, when applied to rate base, will provide the funds necessary to service the various forms of capital. Thus, the total WACC corresponds to a fair rate of return for the utility company.

G. Capital Structure and Embedded Costs

The capital structure the Staff used for this case is Empire's capital structure on a consolidated basis, as of December 31, 2007. Schedule 9 presents Empire's capital structure and associated capital ratios. The resulting capital structure consists of 50.82 percent common stock equity, 44.61 percent long-term debt and 4.58 percent trust preferred stock.

The amount of long-term debt outstanding on December 31, 2007, was $473,334,275 and includes current maturities due within one year. The amount of long-term debt in the capital structure is shown on Schedule 10.

The amount of preferred stock outstanding on December 31, 2008 was $48,544,208 as shown on Schedule 11. It should be noted that Empire's issued preferred stock, known as "Trust Owned Preferred Stock," or TOPRS, is a hybrid between debt and equity. It has the tax deductibility of interest, like debt, and the option of deferring the dividends, like equity. Empire's financial statements classify its preferred stock as debt.

I did not include Empire's short-term debt in the capital structure because as of December 31, 2007, Empire's Construction Work In Progress (CWIP) balance exceeded its short-term debt balance. The capital that supports the CWIP should not be included in the ROR recommendation, because it is assumed that CWIP will be re-financed in the future with long-term debt.

Schedule 7 presents Empire's capital structure for the last five years. Long-term debt has averaged 49.45 percent (including TOPRS), common equity has averaged 47.95 percent, and short-term debt has averaged 2.60 percent. The embedded cost of long-term debt and preferred stock for Empire as of December 31, 2007, was 6.80 percent and 8.88 percent respectively. Please see Schedules 10 and 11.

H. Cost of Common Equity

In order to calculate the cost of common equity for Empire, the Staff performed a comparable company analysis of sixteen companies because these companies have similar electric operations that are comparable to Empire. The Staff selected the discounted cash flow (DCF) model (explained in detail in Attachment D) as the primary tool to determine the cost of common equity for Empire. The Staff also selected the Capital Asset Pricing Model (CAPM) (explained in detail in Attachment E) to check the reasonableness of the DCF results.

The Staff first relied on Value Line's classification system, which specifies companies that they consider to be electric utilities. Schedule 12 presents a list of the sixty-one electric utility companies that Value Line currently classifies as electric utility companies. The Staff then applied the following criteria to these sixty-one companies in order to select the ultimate proxy group:

1. Stock publicly traded: This criterion did not eliminate any companies;
2. Information printed in Value Line: This criterion did not eliminate any companies;
3. Ten years of data available: This criterion eliminated twelve additional companies;
4. Percent of electric utility revenues greater than or equal to 70 percent: This eliminated twenty-four companies;
5. No pending merger in the last six months: This criterion did not eliminate any companies.
6. No reduced dividend in the last ten years: This criterion eliminated eight additional companies.
7. Two sources for projected growth with one available from Value Line: This criterion did not eliminate any companies.
8. At least investment grade credit rating: This criterion eliminated two additional companies.

This resulted in a group of sixteen publicly-traded electric utility companies. The comparables are listed on Schedule 13.

The Staff calculated a DCF cost of common equity for each of the comparables. The first step was to calculate a growth rate. The Staff reviewed the actual dividends per share (DPS), earnings per share (EPS), and book values per share (BVPS) as well as projected EPS growth rates for the comparables. Schedule 14-1 lists the annual compound growth rates for DPS, EPS, and BVPS for the past ten years. Schedule 14-2 lists the annual compound growth rates for DPS, EPS, and BVPS for the past five years. Schedule 14-3 presents the averages of the growth rates shown in Schedules 14-1 and 14-2. Schedule 15 presents the average historical growth rates and the projected growth rates for the comparables. The projected EPS growth rates were obtained from three outside sources; I/B/E/S Inc.'s Institutional Brokers Estimate System, S&P's Earnings Guide, and The Value Line Investment Survey: Ratings and Reports. The three projected EPS growth rates were averaged to develop an average projected growth rate of 7.04 percent, which was averaged with the historical growth rates to produce a historical and projected growth rate of 4.25 percent. Because of the volatility of historical growth rates, the Staff chose to rely primarily on the projected growth rates to arrive at a growth rate range for the comparables of 5.55 percent to 6.70 percent.

The next step was to calculate an expected yield for each of the comparables. The yield term of the DCF model is calculated by dividing the amount of the expected DPS payment over the next twelve months by the market price per share of the firm's stock. Even though a strict technical application of the model requires the use of a current spot market price, the Staff chose to use a monthly average market price for each of the comparables. The Staff used this averaging technique to minimize the effects on the dividend yield which can occur due to daily volatility in the stock market. Schedule 16 presents the average high / low stock price for the period of September 1, 2007, through December 31, 2007, for each comparable. Column 1 of Schedule 17 indicates the expected dividend for each comparable over the next 12 months as projected by The Value Line Investment Survey: Ratings & Reports, November 30, December 28, 2007, and February 8, 2008. Column 3 of Schedule 17 shows the projected dividend yield for each of the comparables. The dividend yield for each comparable was averaged to calculate the projected dividend yield of 3.73 percent.

As illustrated in Column 5 of Schedule 17 the average cost of common equity based on the projected dividend yield added to the average of historical and projected growth is 8.36 percent. However, this is not the Staff's recommendation because in this case, the historical growth rates are somewhat volatile. As a result, the Staff decided to rely on the projected growth rates that were analyzed. Giving complete weight to the projected growth rates, the Staff's DCF proxy group cost of common equity estimation is 9.28 percent to 10.43 percent.

To verify the reasonableness of the Staff's DCF cost of common equity, the Staff performed a CAPM cost-of-common-equity analysis for the comparables. For purposes of this analysis, the risk-free rate the Staff used was the yield on Thirty-Year U.S. Treasury Bonds. The Staff determined the appropriate rate to be the average yield for the month of January 2008. The average yield of 4.33 percent was provided on the St. Louis Federal Reserve website. For the second variable, beta, the Staff researched Value Line in order to find the betas for the comparable group of companies. Schedule 18 contains the appropriate betas for the comparables. The final term of the CAPM is the market risk premium (Rm - R f). The market risk premium represents the expected return from holding the entire market portfolio less the expected return from holding a risk-free investment.

The first risk premium used was based on the long-term, arithmetic average from 1926 to 2006, which was 6.50 percent. The second risk premium was based on the long-term, geometric average from 1926 to 2006, which was determined to be 5.00 percent. The third risk premium was based on a ten-year geometric average from 1996 to 2006, which was determined to be .59 percent. These risk premiums were taken from Ibbotson Associates, Inc.'s Stocks, Bonds, Bills, and Inflation: 2007 Yearbook.

Schedule 18 presents the CAPM analysis of the comparables using historical actual return spreads to estimate the required equity risk premium. The CAPM analysis produces an estimated cost of common equity of 9.83 percent for the comparables when using the long-term arithmetic average risk premium period; using the long-term geometric average produces an estimated cost of common equity of 8.56 percent and using the short-term risk premium period produces an estimated cost of common equity of 4.83 percent.

The results of the Staff's DCF and CAPM estimated ROE analyses using the comparable company approach are summarized below.

	DCF	CAPM (Historical)
Comparable Companies	9.28% - 10.43%	Historical - 9.83%; 8.56%; 4.83%

As noted above, the Staff's DCF analysis resulted in a ROE range of 9.28 percent to 10.43 percent. Because the average credit rating of the comparable companies is BBB and the credit rating of Empire is BBB-, the Staff increased the lower end and the upper end of the range by 12 basis points to reflect the higher risk implied by this credit rating differential. The recent spread between A-rated utility bonds and BBB-rated utility bonds is 35 basis points. This approximately equates into a 12 basis point differential for each notch within the credit rating and because Empire's credit rating is one notch below the average credit rating of the comparable companies, the Staff believes it is appropriate to adjust the proxy group cost of common equity estimate up by 12 basis points. Therefore, the Staff recommends a return on common equity in the range of 9.40 percent to 10.55 percent based on the results of its comparable company DCF analysis.

I. Conclusion

The cost of service ratemaking method was adopted in this case. This approach develops the public utility's revenue requirement. The cost of service (revenue requirement) is based on the following components: operating costs, rate base and a return allowed on the rate base (see Schedule 20).

It is the Staff's responsibility to calculate and recommend a rate of return that should be authorized on the Missouri jurisdictional electric utility rate base of Empire. Under the cost of service ratemaking approach, a weighted cost of capital in the range of 8.22 to 8.80 percent was developed for Empire's electric utility operations (see Schedule 21). This rate was calculated by applying an embedded cost of long-term debt of 6.80 percent, an embedded cost of preferred stock of 8.88 percent and a cost of common equity range of 9.40 percent to 10.55 percent to a capital structure consisting of 44.61 percent long-term debt, 4.58 percent preferred stock, and 50.82 percent common equity. Therefore; from a financial prospective Staff is recommending to the Commission that Empire's electric utility operations be allowed to earn a return on its original cost rate base in the range of 8.22 to 8.80 percent. The Staff's midpoint ROE recommendation is 9.98%

It is Staff's expert opinion that through its analysis it has developed a fair and reasonable return, which when applied to Empire's jurisdictional rate base will allow Empire the opportunity to earn the revenue requirement developed in this rate case.

The Staff and Empire have both recommended implementation of a fuel adjustment clause (FAC) for Empire in this proceeding. All the Staff's comparable companies operate under a mechanism similar to an FAC. In the event the Commission approves an FAC for the Company in this case, and the Commission believes that such implementation materially reduces Empire's risks, and hence its return on equity, the Staff recommends that the Commission move to the lower end of the Staff's recommended ROE range in this case.
Staff Expert: Matthew J. Barnes

VI. Rate Base

A. Plant in Service and Depreciation Reserve

1. In-Service Criteria for Riverton 12 Unit

The Staff and EDE previously agreed on a set of in-service criteria to verify that the Riverton 12 generating unit was fully operational and used for service, and should be considered for inclusion in rate base.

EDE's new Riverton 12 generating unit is a Siemens-Westinghouse V84.3A2 (Siemens SGT-6-4000F) natural gas-fired combustion turbine-generator with a nominal capacity of 155 MW. The specific criteria and Staff's evaluation notes are attached as Appendix 3 to this report. Based on the Staff's on-site observation of the unit, supplemented by review of test records, operating logs, computer data, and other documentation, the Staff concludes that the generating unit successfully met all of the in-service criteria and was fully operational and used for service in July 2007, prior to the end of the update period for this case, December 31, 2007.
Staff Expert: Michael E. Taylor

2. Construction Audit of the Riverton 12 Unit

Empire installed a new 155 MW combustion turbine at its Riverton Generating Station which began providing energy to the grid in April 2007. Staff audited the construction costs of this project to determine the proper total cost for this project to be included in Empire's rate base.

The Staff's audit uncovered no concerns with the project. Based on its review of the construction of this unit, the Staff is not recommending any adjustments.

Staff's audit consisted of a review of the project authorizations, contracts, purchased orders, change orders, invoices, and plant account documents associated with this project. Staff visited the Riverton Station in January 2005, October 2005, February 2006, June 2006 and October 2007 to review the project construction.

Staff Expert: David W. Elliott

3. Plant in Service as of December 31, 2007

Accounting Schedule 3, Plant in Service, reflects the rate base value of Empire's plant in service at December 31, 2007, by account. The Staff has adjusted Empire's plant balances in Plant adjustments P-77 through P-87 to allocate a portion of the Company's general plant to Empire's natural gas business. These adjustments are necessary as Empire records its general plant in service on its electric books in entirety.

Staff Expert: Paula Mapeka

4. Depreciation Reserve as of December 31, 2007

Accounting Schedule 4, Depreciation Reserve, reflects the rate base value of Empire's depreciation reserve at December 31, 2007, by account. The Staff has adjusted Empire's reserve balances in Reserve adjustments R-68 through R-77 to allocate a portion of the Company's depreciation reserve associated with its general plant to Empire's natural gas business. These adjustments are necessary as Empire records its general depreciation reserve associated with general plant on its electric books in entirety.

Staff Expert: Paula Mapeka

B. Cash Working Capital (CWC)

The Staff has used the same revenue and expense lag factors that it recommended in its lead/lag study in Empire's last Missouri rate proceeding, Case No. ER-2006-0315. The Company used the same factors in its direct filing; accordingly, there are no contested issues between Empire and the Staff related to CWC in this rate case.

Staff Expert: Paula Mapeka

C. Prepayments, and Materials and Supplies

The Company has utilized shareholder funds for prepaid items such as insurance premiums and postage. The Staff has included these prepayments in rate base at the 13-month average level ending December 2007. The Company also holds a variety of materials and supplies in inventory so as to be readily available in performing its utility operations. The Staff has included in rate base the 13-month average value ending December 2007 of Empire's materials and supplies inventory.

Staff Expert: Paula Mapeka

D. Fuel Inventories

The Staff used the results of its fuel model to calculate the annual amount of coal used by each plant to meet the normalized native load. ("Native load" is the demands placed upon Empire's system by its regulated retail electric customers.) To arrive at the average daily burn by unit, the annualized tons burned is divided by 365 days. Then, the average daily burn is multiplied by an appropriate number of days of inventory for each plant. The number of days inventory of Powder River Basin (PRB) or "western" coal for the Asbury 1 and 2 units is set at 60 days. This same value for Riverton 7 and 8 was calculated to be 55 days. This PRB Coal is currently supplied by three western coal suppliers: Arch Coal Sales, Peabody Coal Trade and Peabody Coal Sales. EDE also carries an inventory of local (Kansas) coal supplied by Phoenix Coal Company and petroleum coke by Oxbow Carbon and Mineral, both under contract; the days of inventory included for this coal and petroleum coke is also 55 days. The Staff multiplied the total tonnage of inventory for each unit by the Staff's proposed delivered cost of coal per ton for that unit. This dollar amount was multiplied by the Staff's energy jurisdictional factor with the result being the amount that is reflected as part of Fuel Inventories in Accounting Schedule 2, Rate Base.

Fuel Oil Inventory - The Staff used the 13-month average inventory quantities and a weighted average price for oil inventory levels

Staff Expert: Dana E. Eaves

E. Gas Stored Underground

Empire maintains an inventory of stored gas to help meet its gas needs at peak periods. An average 13-month calculation of volumes of gas stored underground by Empire for the period of January through December 2007 was used, priced at the weighted average cost of the gas stored during this period to value this rate base item.

Staff Expert: Dana E. Eaves

F. Prepaid Pension Asset / FAS 87 Regulatory Asset Tracker / FAS 106 Regulatory Asset Tracker

See the discussion of these items in Section VIII.F.1., FAS 87/Pension Expense and Section VIII.F.2, FAS 106/OPEBs Expense.

Staff Expert: Dana E. Eaves

G. Customer Demand Programs Regulatory Asset

Empire is currently working with the Customer Programs Collaborative (CPC) that was created as a result of the Stipulation and Agreement in Case No. EO-2005-0263, Empire's "Iatan II Regulatory Plan" case. The CPC retained a consultant to evaluate Demand Side Management (DSM) and affordability programs for Empire's Missouri customers. All actual costs associated with the CPC and new DSM programs are to be included in rate base as a regulatory asset, per the Stipulation And Agreement in Case No. EO-2005-0263. There is also an adjustment in the Income Statement to amortize these costs to expense (see Section VIII.H.15.c.).

Staff Expert: Amanda C. McMellen

H. Amortization of Electric Plant

The Staff has adjusted the amortization reserve for electric plant to reflect the updated balances through December 31, 2007. The reserve was also adjusted to eliminate expired amortizations and include new amortizations within the test year and update period.

Staff Expert: Amanda C. McMellen

I. Customer Deposits

The amount of customer deposits on Accounting Schedule 2, Rate Base, represents a 13-month average (December 2006 – December 2007) of Empire's customer deposits. Customer deposits represent funds received from utility companies' customers as security against potential loss arising from failure to pay for utility service. Since the deposits are interest-free loans to the company, a representative level is included as an offset to the rate base investment. Generally, interest is calculated on customer deposits. The amount of interest calculated on customer deposits is reflected on Staff Accounting Schedule 10 as adjustment S-82.1.

Staff Expert: Paula Mapeka

J. Customer Advances

Customer advances are funds provided by individual customers of the Company to assist in the costs of the provision of electric service to them. These funds represent interest-free money to the Company. Therefore, it is appropriate to include these funds as an offset to rate base. No interest is paid to customers for the use of their money, unlike customer deposits. The amount of customer advances reflected on Accounting Schedule 2, Rate Base represents the balance as of December 31, 2007, the end of the Staff's update period, with one adjustment. Empire's balance of customer advances as of December 31, 2007, was adjusted to reflect imputation of an amount that should have been received by Empire from the developers of The Lakes at Schuyler Ridge subdivision. Empire's tariffed extension policy requires the developer to make full payment of the estimated charges for an extension of service to a subdivision in advance of any construction. In Case No. EO-2008-0043, Empire's application stated that the Empire total system expenses incurred for this subdivision was $801,120 as of July 14, 2007, but this amount was not collected from the developer as Empire's tariffs required. If the provisions of Empire's tariffs had been followed, this amount would have been booked as a customer advance.

Staff Experts: Paula Mapeka and Daniel I. Beck

K. Deferred Income Taxes

Empire's deferred tax reserve represents, in effect, a prepayment of income taxes by Empire's customers prior to payment by Empire. As an example, because Empire is allowed to deduct depreciation expense on an accelerated basis for income tax purposes, depreciation expense used for income taxes paid by Empire is considerably higher than depreciation expense used for ratemaking purposes. This results in what is referred to as a "book-tax timing difference," and creates a deferral of income taxes to the future. The net credit balance in the deferred tax reserve represents a source of cost-free funds to Empire. Therefore, Empire's rate base is reduced by the deferred tax reserve balance to avoid having customers pay a return on funds that are provided cost-free to the Company. Generally, deferred income taxes associated with all book-tax timing differences that are created through the ratemaking process should be reflected in rate base. The Staff has taken this approach in calculating the deferred income tax rate base offset amount in this case. The deferred tax impact of the following past tax timing differences were included in the Staff's rate base offset: Accelerated Depreciation, Loss on Hedge Transactions, Gain on Hedge Transactions, License Software Amortization, Loss on Reacquired Debt, Ice Storm Expenses, Contributions in Aid of Construction, Post-retirement Benefits – Pensions, and Capitalized Interest.

Staff Expert: Amanda C. McMellen

L. Regulatory Plan Additional Amortization - Rate Base

A Stipulation and Agreement titled, "Nonunanimous Stipulation and Agreement Regarding Regulatory Plan Amortizations" was filed in Empire's last rate case, Case No. ER-2006-0315. Paragraph 5 provides for a rate base offset consisting of the accumulated balance of the Regulatory Plan Additional Amortization collected in rates:

> Further, Empire acknowledges that this Agreement is a resolution and is an implementation of the resolution of the gross-up issue that was intentionally left unresolved by the Regulatory Plan Stipulation And Agreement in Case No. EO-2005-0329. This resolution is implemented pursuant to and in compliance with the provisions of that Stipulation And Agreement, and that as a result thereof, any Regulatory Plan additional amortization that is provided to Empire pursuant to that Stipulation And Agreement shall be used as reduction to rate base for the longer of (a) at least ten (10) years following the effective date of the July 28, 2005 Report And Order in Case No. EO-2005-0329 or (b) until the investment

> in the plant in service accounts to which the Regulatory Plan amortizations are ultimately assigned by the Commission is retired. Such reduction to rate base is understood and accepted by Empire without reservation.

The revenue requirement approved by the Commission's Report and Order in Case No. ER-2006-0315 included a Regulatory Plan Amortization in the amount of $10,469,228. Empire began recovering the Regulatory Plan Amortization beginning January 1, 2007, the effective date of the Commission's Report and Order. The Staff has reflected a rate base offset of $10,469,228 representing the amount of the Regulatory Plan Additional Amortization collected in rates as of the end of the update period, December 31, 2007, used for the Staff's direct filing.

Staff Expert: Mark L. Oligschlaeger

VII. Allocations

A. Jurisdictional Allocations

The Staff used the 12-coincident peak (12cp) method to determine Empire's jurisdictional demand allocation factors in this proceeding. The 12cp method is consistent with that used in prior Empire rate cases and with what Empire is recommending in the current case.

Staff Expert: Erin Maloney

B. Corporate Allocations

As discussed earlier in this report, Empire is engaged in different business segments, both regulated and non-regulated. In this audit, the Staff reviewed Empire's methods for assigning and allocating costs to its electric, gas, water and non-regulated operations. Under Empire's corporate cost allocation system, the costs are either directly assigned to business units (Empire refers to this as "direct billing"), indirectly allocated to the business units. or allocated through use of a general factor.

Direct assignment is the preferred method of assigning costs, whenever possible. Certain costs are directly assigned to Empire's electric operations by use of either vendor invoices or by labor charges. Each vendor invoice that includes charges for goods and services that are a direct benefit to a specific business unit are directly assigned to the appropriate business unit. The other direct assignment method is by labor. All employees are required to record their time electronically and to allocate their time based on the time each employee spends each month working on each business unit. Then, the system appropriately allocates a portion of that employee's salary to the appropriate business unit. The portion allocated to each business unit includes not only salary but also associated payroll taxes and fringe benefits.

Empire's indirect allocation factor is based upon a unit of service method. For costs incurred that can not be directly billed to the individual business units, Empire uses the unit service method based on certain unit drivers. Examples of Empire's unit drivers are as follows: number of vouchers, number of active customers, number of purchase orders and number of personal computers. A rate is calculated based on information obtained from various general ledger entries and adjusted periodically.

For costs that cannot be direct assigned or have no unit drivers, a "Modified Massachusetts" formula is used. A "Massachusetts formula" is a general allocation factor based upon three separate measurements of direct assigned costs, and is used to allocate a company's common costs that cannot be reasonably directly assigned or indirectly allocated to a company's business units. The Modified Massachusetts formula used by Empire consists of the averages of (1) profit margin, (2) payroll and net property, and (3) plant and equipment.

The Staff has reviewed Empire's methods for allocating costs among its different business units, and believes they are reasonable. The Staff is proposing an adjustment to annualize test year allocations of common costs to Empire's gas operations to reflect the allocation factors that were in place at the end of that twelve-month period (and still are in effect currently).

Staff Expert: Amanda C. McMellen

VIII. Income Statement

A. Rate Revenues

1. Introduction

Since the largest component of operating revenues result from rates charged Empire's Missouri retail customers, a comparison of operating revenues with cost of service is fundamentally a test of the adequacy of the currently effective Missouri jurisdictional retail electricity rates. If the overall cost of providing service to Missouri retail customers exceeds operating revenues, an increase in the current rates Empire charges its Missouri retail customers for electricity is required.

One of the major tasks in a rate case is to not merely determine whether a deficiency (or excess) between cost of service and operating revenues exists but to determine the magnitude of any deficiency (or excess) between cost of service and operating revenues. Once determined, the deficiency (or excess) can only be made up (or otherwise addressed) by adjusting Missouri retail rates (i.e., rate revenues) prospectively.

2. Definitions

Operating Revenues are composed of Rate Revenue, Margin from Off-System Sales, and Other Operating Revenue.

Rate Revenue: Test year rate revenues consist solely of the revenues derived from Empire's charges for providing electric service to its Missouri retail customers (native load). Empire's charges are determined by each customer's usage and the (per unit) rates that are applied to that usage. In Missouri, different rates apply to different times of the year (summer vs. winter); different types of charges (demand vs. energy); and to customers in different rate classes (differentiation by type and amount of use).

Margin from Off-System Sales: Margin from off-system sales is the profits that Empire makes conducting sales of electricity to other utilities at non-regulated prices. The profit (margin) is calculated as the gross revenues from the sale less the expenses Empire incurs. The rationale for assigning the profits to ratepayers is that the electricity being sold is generated by power plants being paid for by ratepayers.

Other Operating Revenue: Other operating revenue includes Forfeited Discounts (bad debts), Reconnect Charges, Rent from Electric Property and Miscellaneous Electric Revenues.

3. The Development of Rate Revenue in this Case

The objective of this section is to determine annualized, normalized test year sales and revenues by rate classes. This section also includes a discussion of the annualization of Excess Facilities Charges.

The intent of the Staff's adjustments to test year Missouri sales and rate revenues is to determine the level of revenue that the Company would have collected on an annual, normal-weather basis, based on information "known and measurable" at the end of the update period.

The two major categories of revenue adjustments are known as "normalizations" and "annualizations". Normalizations deal with test year events that are unusual and unlikely to be repeated in the years when the new rates from this case are in effect. Test year weather is an example. Annualizations are adjustments that re-state test year results as if conditions known at the end of the update period had existed throughout the entire test year.

4. Regulatory Adjustments to Test Year Sales and Rate Revenue

a. Normalization of Usage

Empire's load contains a high saturation of air conditioning and the presence of significant electric space heating. As a result, the magnitude and shape of many of Empire's class loads are directly related to daily temperatures.

During the test year, the months of December 2006 and January 2007 were warmer than normal. The warmer than normal temperatures resulted in decreased energy consumption due to lower than normal heating usage. The months of July through September 2006 and June 2007 were warmer than normal. These warmer than normal temperatures resulted in increased energy consumption due to higher than normal cooling usage.

Since the actual daily temperatures during the test year varied from normal conditions, a weather impact analysis is needed to adjust for these conditions. The following classes were weather normalized: Residential (RG), Commercial (CB), Small Heating (SH), Total Electric Building (TEB), and General Power (GP).

The usage data, provided by EDE in response to Staff Data Request No. 163, was separated by known billing corrections (bad original bill and subsequent cancellation) and correct billing. While reviewing this billing data, I noticed that the usage in some billing cycles for the known billing corrections was large and negative, indicating billing corrections had occurred and, accordingly, the bad original bill was not in the correct month or was not indicated as being cancelled. I was able to eliminate the negative known billing correction usage by combining obvious incorrectly billed usage with the corresponding canceled usage and rebilled usage from the billing cycle data.

Using class specific multivariate regression models within the MetrixND® software package, each class' load was modeled using actual temperatures and simulated under normal temperatures. Staff witness Manisha Lakhanpal, of the Energy Department, provided actual and normal daily temperatures.

Staff witness Curt Wells of the Energy Department used each class weather normalization load adjustment to calculate the overall weather normalization revenue adjustment.

Staff Expert: Shawn E. Lange

b. Weather Normal Variables

Electric rates are based on an expectation of "normal" weather. (Normal weather is defined as the average daily temperatures over a 30-year period.) The weather experienced during the test year is unique and unlikely to be repeated in the years when the new rates from this case are in effect. In order to normalize test year sales, usage is adjusted to the level that would be expected under "normal" weather.

Staff selected the Springfield, MO weather station to develop "normal" average temperatures with which to compare the test year temperature. The time period used in determining the normal values of weather variables is the 30-year period (January 1, 1971-December 30, 2000), which is used by the National Oceanic and Atmospheric Administration (NOAA) and the World Meteorological Organization (WMO) to calculate normal weather variables. Since NOAA makes adjustments to monthly temperatures over the 30-year normals period, these normals are not directly usable for the Staff's purposes. The reason is that daily normal temperatures need to be developed to adjust electricity usage to normal levels. Therefore, Staff is required to adjust the historical actual daily data series to correspond with NOAA's monthly average.

Staff uses normal weather "ranking" method in the normalization of both class usage and hourly net system loads. This ranking method estimates daily normal values, ranging from the temperature that is "normally" the hottest to the temperature that is "normally" the coldest, thus estimating normal extremes. The daily normals are calculated by averaging the ranked temperatures in each year of the 30-year normals period, irrespective of the calendar date. This results in the normal extreme being the average of the most extreme temperatures in each year of the normals period. The second most extreme temperature is based on the average of the second most extreme day of each year, and so forth. These temperatures are then assigned to the days of the test year based on the rankings of the actual temperatures of the test year. This information was provided to Staff witness Shawn E. Lange for weather normalization.

For more information on the methodology used please refer to "Weather Normalization of Electric Loads, Demonstration: Calculation of Weather Normals" (October 25, 1991), written by Martin Turner, the former Manager of Missouri Public Service Commission's Research and Planning Department.

Staff Expert: Manisha Lakhanpal

c. Weather Normalization of Sales and Revenue

Sales and revenue were normalized for the Residential, Commercial, Small Heating, Total Electric Building, and General Power rate classes.

For the Residential Commercial, and Small Heating rate schedules, I used test year data and a statistical technique known as a regression to model the relationship between average use per customer and the percentage of test year kWhs that are priced in the first rate block. I then applied this relationship to the monthly use per customer before and after the weather adjustment that Staff witness Shawn E. Lange had provided me. This computation resulted in normalized kWhs by rate block, which were then converted to total normalized revenues by multiplying rate block kWh by the appropriate rates.

For the General Power and Total Electric Buildings rate schedules, the weather adjustment to rate revenues was calculated by an average realization methodology, excluding customer and demand charges. This methodology assumes that the weather adjustment to kWh sales in each month is distributed into the rate blocks in proportion to the distribution of actual test year energy. Another interpretation of this average realization methodology is that any additional kWh sales due to weather normalization should be priced at the same average price as all other sales in that month.

The General Power Class billing units and revenues were further subdivided by voltage to allow their use in rate design. The primary voltage billing units and associated revenues were provided by Staff witness David Roos.

Staff Expert: Curt Wells

d. Missouri General Power Service – Primary Service

To obtain billing units necessary to calculate revenues and design rates, Staff determined the billing units and rate revenue for the group of Missouri customers in the General Power (GP) Service Class that were metered at primary voltage during the test year. Raw billing data for individual customers was extracted from the dataset provided in response to Staff Data Request No. 160. Bad original bills and cancellations and rebills were removed from the dataset. Rebills were re-dated based on the usage date and revenue month. These tasks produced a data set of individual customer billing data, including billing units and rate revenues, for the GP customers metered at primary voltage without the affects of billing errors. Customer data was then aggregated by month and by season for the test year.

Staff Expert: David Roos

e. Annualization for Rate Change

Test year rate revenues do not fully reflect the rate changes implemented on January 1, 2007, as a result of Case No. ER-2006-0315. Thus test year revenues are understated by the difference between the amount that was actually billed to customers and the revenue that would have been realized by the Company if the current rates had been in effect throughout the entire test year. Staff's method of computing annualized revenues for each rate class was to multiply test year billing units by current rates. The difference between these revenues and those billed during the test year under the prior rates (permanent rate plus the Interim Energy Charge rate) provided the amount of the adjustment.

Staff Expert: Curt Wells

f. 365-Days Adjustment

Since revenue months are an aggregation of bill cycles, they will differ from calendar month by the time period they cover. Thus, the test year on a calendar month basis time period will differ from the test year on a revenue month basis time period. In order to account for this difference, I calculated a "days" adjustment to adjust the annual weather normalized revenue month kWh sales to coincide with the annual weather normalized calendar month kWh sales. This annual adjustment was disaggregated to the test year months by the percent of actual kWh sales occurring in each month.

Staff Expert: Shawn E. Lange

g. Customer Growth (Annualization)

The Staff made customer growth adjustments to test year kWh sales and rate revenue to reflect the additional kWh sales and rate revenue that would have occurred if the number of customers taking service at the end of the update period (December 31, 2007) had existed throughout the entire test year. Customer growth was calculated for the Residential, Commercial, Small Heating, Total Electric Building, and General Power customer classes.

The only retail customer rate class for which this approach is not taken is the Large Power group. The process used for the Large Power group is described in part e. below. Energy consumption and revenue patterns are considered to vary significantly across this group of customers, making it necessary to examine the history of each customer on an individual basis, and to adjust the test year revenue level accordingly. The Staff's customer growth adjustment to test year revenues for all retail customer groups combines the results of the analysis described above for Residential, Commercial, Small Heating, Total Electric Building, and General Power, in order to provide the annualized level of sales and revenues at December 31, 2007. The adjustment for retail customer growth other than Large Power is S-1.2.

Staff Expert: Amanda C. McMellen

h. Large Customer, Praxair and Non-Missouri Large Power Customer Annualizations

The objective of this section is to determine annualized, normalized test year sales and revenues for the rate classes determined not to be weather sensitive, i.e., the Large Power Customers (LP), Praxair, and Non-MO Large Power Customers.

The adjustments are for the test year of July 1, 2006 – June 30, 2007, updated for known and measurable changes through December 31, 2007. There were 38 customers in the MO LP rate class during the test year. A data check was done for billing corrections prior to making adjustments.

Because each Large Power customer uses significant amounts of electricity, and the class is heterogeneous in electric use and load factor, class sales and revenues were annualized on an individual customer (account) basis. Each customer's individual monthly demand and energy use, measured over multiple years prior to the test year, the 12 months of the test year, and the three-month update period, were examined graphically to determine whether an adjustment was needed.

Out of the 38 MO LP customers, only two LP customers' loads were adjusted; one GP customer was added to LP, and one LP customer was removed because it switched to the GP rate class. The load adjustments were done by replacing the non-representative monthly usage by either average numbers from preceding and/or following months within the test year. The customer who switched into the LP class was annualized as an LP customer, with a corresponding adjustment to reduce test year sales for the GP class. Similarly, sales and revenues were updated for the LP class to account for the customer who rate switched from LP to GP.

Staff Expert: Manisha Lakhanpal

i. Special Contract Revenue Imputation

The special treatment of the interruptible credits associated with Praxair's contract stipulated in Case No. ER-2001-299 was continued, but revenues were imputed to prevent harm to other ratepayers.

Staff Expert: Manisha Lakhanpal

j. Non-Missouri Adjustments

The "days adjustment" to Sales was the only annualization done for Non-Missouri LP customers. Non-Missouri sales are adjusted because they are included in Net System Load.

Staff Expert: Manisha Lakhanpal

k. Rate Switching

During this particular test year 49 customers were in the CB rate class for a portion of the year and in the GP rate class for the remainder of the year. Also, there were 26 customers in the GP rate class for a portion of the year and in the CB rate class for the remainder of the year. These customers are known as "rate switchers" because they switched from one rate class to another. Billing information indicated that this rate switching was likely due to economic reasons (i.e., to lower the customer's bill) rather than load growth or decline. While the overall effect of rate switching on kWh sales nets to zero (one class' increase exactly equals the other class' decrease), the effect is to reduce overall rate revenues.

Those customers who switched in and out of GP and CB classes were handled separately. The billing units and revenue of these customers were removed from their original rate code.

Their total billing units for the test year were then re-priced based on their final rate code and their revenues were added to the final rate code.

Staff Experts: Curt Wells and Amanda C. McMellen

l. Annualization of Excess Facility Charge Revenues

These revenues result from charges to customers for facilities provided in excess of those normally made available. These revenues are annualized to determine the revenue that would have been earned had these facilities been in use the entire test year.

Staff Expert: Curt Wells

m. Results

The results of test year adjustments to the classes' rate revenue can be found in Appendix 4 to this Report.

B. Off-System Sales and Transmission Revenue

1. Off-System Sales (OSS)

The Staff has annualized Empire's OSS by totaling the Company's margin (revenues less expenses) from its OSS transactions from January 1 to June 30, 2007, and multiplying this amount by two. This results in an adjusted level of OSS margin of $4,415,779, compared to a test year level of $3,920,819, and a level for the twelve months ended December 31, 2007, of $5,955,336. The Staff believes that its approach giving greater weight to Empire's more recent OSS experience is appropriate for annualizing OSS margins due to recent changes in Empire's OSS environment.

Starting in February 2007, Empire has participated in the Energy Imbalance System (EIS) Market operated and controlled by the Southwest Power Pool (SPP). The EIS market is intended to allow member utilities access to economical real time energy based upon market bids by members and the availability of dispatchable generation and transmission within the SPP market footprint.

Since Empire began participating in the EIS market, it has been a net seller of power into the market. Involvement in the EIS market has benefited Empire with increased margins from the sale of power. Empire has cited this benefit from participation in the SPP EIS Market in its Form 10-K and 10-Q filings with the Securities and Exchange Commission (SEC).

Empire has also derived substantial margins from a sale of capacity and energy to the Kansas City, Kansas - Board of Public Utilities (BPU) in summer 2007. The BPU transaction is ongoing in nature, as it will be in effect for the summer of 2008 as well.

For these reasons, the Staff asserts that its recommended level of OSS margin is a reasonable ongoing level to include in Empire's revenues. The Staff's adjustment to test year OSS margins is No. S-85-2 in Accounting Schedule 10, Adjustments to the Income Statement.

Staff Expert: Dana E. Eaves

2. Transmission Revenue

Like OSS margins, the Staff is recommending a level of transmission transaction margins based upon the first six months in 2007 (January through June monthly margins, multiplied by two). Consistent treatment of OSS and transmission margins is appropriate since Empire totals these two transaction types together for purposes of reporting "off-system sales" results in its SEC reporting. The Staff adjustment S-85.1 increases test year transmission transaction margins by $70,149, for a total amount of $679,317.

Staff Expert: Dana E. Eaves

C. Miscellaneous Revenues

1. SO2 Allowances

On January 18, 2005 the Commission approved the Unanimous Stipulation and Agreement relating to EDE's "SO2 Allowance Management Policy (SAMP)" in Case No. EO-2005-0020. In this document, the parties agreed that Empire should be allowed to manage its sulfur dioxide emissions allowance inventory according to the "SAMP" as detailed in this case.

In accordance with this agreement and past ratemaking practice, the Staff is proposing an adjustment to Other Operating Income in the amount of $51,805, reflected as adjustment S-86.1. This adjustment reflects above-the-line inclusion in revenues of the gain on the sale of SO2 Allowances by Empire for the twelve months ended December 31, 2007.

Staff Expert: Dana E. Eaves

2. Water Revenues

There are amounts recorded by Empire in the test year as electric revenues that relate to forfeited discounts and returned check fees for Empire's water business. The Staff has eliminated these revenues from the revenue requirement in this case in adjustment S-1.11.
Staff Expert: Amanda C. McMellen

3. Other Revenues

Empire's "other" revenues include forfeited discounts and rents from property. The Staff reviewed Empire's totals of other revenue over the last five years. Based upon this review, the Staff believes Empire's test year level of booked other revenues is representative of an ongoing, annualized level of revenue for each respective category of costs and, therefore, does not require an adjustment.

D. Fuel and Purchased Power

The Staff's adjustments to annualize and normalize Empire's fuel expense are reflected in adjustments S-3.2, S-22.2, S-30.1 and S-30.2 on Accounting Schedule 10, Adjustments to Income Statement.

1. Fixed Costs

Fuel and purchased power costs that do not vary directly with fuel burned were not included in the Staff's fuel model, but were determined separately. The non-variable fuel costs that are included in fuel expense are typically referred to as fuel adders. These costs include unit train lease payments, unit train maintenance, unit train depreciation and unit train property taxes. The non-variable purchased power costs are referred to as capacity charges and these costs are annualized separately from purchased power energy costs. (A unit train is typically a combination of coal cars, 100 or more, which are kept together as one unit, moving coal from one mine to one customer, often one power plant.)

a. Fuel Adders

The costs of fuel adders are determined separately from fuel model costs and are added to the level of fuel expense calculated by the model to determine overall fuel expense. The fuel adders in this case are natural gas transportation costs, storage charges and trucking charges as it

relates to coal hauling from one generating unit to another. The Staff annualized the level of actual expense incurred from January 2007 through June 2007; a trucking charge of $3.34 per ton was added to overall coal costs for the Riverton 7 and 8 units only.
Staff Expert: Dana E. Eaves

b. Purchased Power – Capacity Charges

Capacity charges represent fixed amounts Empire paid to the entity that reserves the MW capacity for Empire. Empire contracts for this power with various entities and pays a fixed component and an energy component. Generally, there is also an amount for operation and maintenance costs charged for the use of energy. The fixed component is paid as a "demand charge," generally on a monthly basis, regardless of the level of power actually purchased. This amount is for the "right" to purchase the power in much the same way that natural gas utilities purchase reservation of capacity from pipelines through reservation payments. The demand charges relate to the fixed expenses of operating a generating facility.

Staff adjustment S-30.1, found in Accounting Schedule 10, annualizes purchased power demand charges. These charges represent amounts that are paid under capacity agreements related to the fixed costs of reserving capacity
Staff Expert: Dana E. Eaves

2. Variable Costs

The Staff estimates the variable fuel and purchased power expense for Empire for the twelve months ending December 31, 2007, to be $149,161,065.

The Staff used the RealTime™ production cost model to perform an hour-by-hour chronological simulation of a utility's generation and power purchases. The Staff uses the model to determine annual variable cost of fuel and net purchased power energy costs and fuel consumption necessary to economically meet a utility's load within the operating constraints of the utility's resources used to meet that load. These amounts are supplied to Auditing Department Staff who use this input in the annualization of fuel expense.

The model operates in a chronological fashion, meeting each hour's energy demand before moving to the next hour. It will schedule generating units to dispatch in a least cost manner based upon fuel cost and purchased power cost while taking into account generation unit operation constraints. This model closely simulates the way a utility should dispatch its generating units and purchase power to meet the net system load in a least cost manner.

Inputs calculated by the Staff are: fuel prices, spot market purchased power prices and availability, hourly net system input (NSI), and unit planned and forced outages. The Staff relied on Empire responses to data requests for factors relating to each generating unit such as: capacity of the unit, unit heat rate curve, primary and startup fuels, ramp-up rate, startup costs, fixed operating and maintenance expense. Information from Empire's firm wholesale loads and firm purchased power contracts such as hourly energy available and prices are also inputs to the model.

Staff Expert: Leon C. Bender

a. Fuel Prices

The Staff computed its level of fuel expense using prices and quantities contracted for by EDE through the end of the test year update period, including prices and quantities agreed to in fuel and freight contracts that became effective as of January 1, 2008. These fuel prices included prices for coal, natural gas and oil, as well as associated transportation charges.

i. Coal Prices

The Staff determined its coal price by generation facility based on a review and analysis of EDE's current coal purchase and coal transportation contracts. The Staff's proposed coal prices reflect EDE's actual contracted coal purchase and transportation prices in effect at January 1, 2008.

Staff Expert: Dana E. Eaves

ii. Natural Gas Prices

The natural gas price used in this case by the Staff of $6.78 per MMbtu is composed of two components: hedged and non-hedged (spot) price. The non-hedged component of natural gas prices were calculated using a twelve-month weighted average of EDE's actual commodity cost of natural gas purchased on the spot market during the test year. The hedged component of natural gas costs was calculated by applying a weighted average for the actual hedged purchases contracted for at year-end 2007 that are applicable to Empire's forcasted gas needs for calendar year 2008. The weighted average price for the hedged component in 2008 is 6.853 $/MMbtu. The Staff weighted the hedged gas price at 87% of its overall gas price recommendation, as

Empire has contracted to meet 87% of its projected natural gas usage in 2008 with hedged gas supplies. EDE's natural gas transportation costs are annualized and normalized separately as a part of fuel adders.

Staff Expert: Dana E. Eaves

iii. Fuel Oil Prices

The Staff used a weighted average price of $1,516.82 cents per MMbtu to determine the fuel oil cost input in the fuel model in this case. EDE burns fuel oil mainly as a secondary fuel or, in some instances, for flame stabilization. EDE does maintain onsite storage at its various facilities in sufficient capacity that only occasional purchases are necessary. As a result, EDE does not contract or hedge oil costs. The Staff contends that using this weighting methodology properly prices out the oil held in storage purchased at lower than current market levels.

Staff Expert: Dana E. Eaves

3. Spot Market Prices

Spot market purchases are purchases of energy made on an hourly basis rather than through a longer-term contract. A utility decides to buy spot energy from one or more suppliers based on the economics and availability of its generating units and capacity purchases. Purchases of spot energy are made in order to lower costs when the spot market price is below both the marginal cost of providing that energy from the company's generating units and the utility's firm capacity purchases. Since the spot market depends on energy supply and demand in each hour, the prices tend to be much more volatile than firm capacity purchases. The Staff used a procedure developed by the Commission's Energy Department- Engineering Section in 1996 that is described in the document entitled "A Methodology to Calculate Representative Prices for Purchased Energy in the Spot Market" (March 18, 1996). The method uses a statistical calculation based on the truncated normal distribution curve to represent the hourly purchased power prices in the spot market.

Empire's actual hourly non-contract transaction prices in the period of twelve months ending December 31, 2007, obtained from the data Empire supplied to comply with 4 CSR 240-3.190 (3.190 data), are used as price inputs in the calculation. The calculation yields

a spot energy price for each hour of the year. For spot purchased energy availability, the Staff used the same availability as Empire used in its model after Staff determined it was reasonable.
Staff Expert: Leon C. Bender

4. Hourly Net System Input

Electricity use is very sensitive to weather conditions. This is due, in large part, to the high saturation of air conditioning and the presence of significant electric space heating on Empire's system. As a result, the magnitude and shape of Empire's hourly net system input is directly related to daily temperatures.

Hourly net system load is the hourly electric supply necessary to meet the energy demands of the Company's customers and the Company's own internal needs. It is net of (i.e., does not include) station use, which is the electricity requirement of the Company's generating plants. The hourly loads used in my analysis of the test year, July 2006 through June 2007, were provided to Staff in response to Data Request No. 137. I also used hourly load data submitted monthly by Empire in compliance with the Commission's rule 4 CSR 240-3.190 to cross check the data request response.

Daily actual and normal temperatures are a key component of any weather impact analysis. During the test year period, July 2006 through June 2007, the actual daily temperatures for the test year differed from normal conditions. Therefore, to reflect normal weather, daily peak and average net system loads are adjusted independently, but using the same methodology. Independent adjustments are necessary because average loads respond differently to weather than peak loads.

Daily average load is calculated as the daily energy divided by twenty-four hours and the daily peak is the maximum hourly load for the day. Separate regression models estimate both a base component, which is allowed to fluctuate across time, and a weather sensitive component, which measures the response to daily fluctuations in weather for daily average loads and peak loads. The regression parameters, along with the difference between normal and actual cooling and heating measures, are used to calculate weather adjustments to both the average and peak loads for each day. Staff witness Manisha Lakhanpal of the Energy Department provided actual and normal daily temperatures. The adjustments for each day are added respectively to the actual average and peak loads for each day. The starting point for allocating the weather normalized daily peak and average loads to the hours is the actual hourly loads. A unitized load curve is calculated for each day as a function of the actual peak and average loads for that day. The corresponding weather normalized daily peak and average loads, along with the unitized load curves, are used to calculate weather normalized hourly loads.

This process includes many checks and balances, which are included in the spreadsheets that are used. In addition, the analyst is required to examine the data at several points in the process. For more information, the process is described in greater detail in the document "Weather Normalization of Electric Loads, Part A: Hourly Net System Loads" (November 28, 1990), written by Dr. Michael Proctor, Manager of the Commission's then-Economic Analysis Department.

Once Staff's calculation of weather normalized, annualized test year usage for both Missouri and non-Missouri was completed, I increased it by the weather normalized wholesale usage. Then, I increased the annual usage by the loss factor supplied to me by Staff witness Alan J. Bax in order to obtain the additional amount of generation (net system input) necessary to serve this additional generation. This produces an annual sum of the hourly net system loads that equals the adjusted test year usage, plus losses, and is consistent with normalized revenues.

A factor was applied to each hour of the weather-normalized loads to produce an annual sum of the hourly net-system loads that equals the adjusted test year usage, plus losses, and consistent with normalized revenues.

Once completed, the test-year hourly normalized system loads and the hourly firm wholesale loads were given to Staff witness Leon C. Bender to be used in developing the Staff's adjusted test year fuel and purchase power expense. Staff witness Erin Maloney used the annual requirement of the net system hours in developing her jurisdictional energy allocator.

Staff Expert: Shawn E. Lange

a. Normal Weather

Please refer to the revenue section of this report (Section VIII.3.) for a description of how Staff calculates normal weather.

i. Losses

System energy losses largely consist of the energy losses that occur in the electrical equipment (e.g., transmission and distribution lines, transformers, etc.) of Empire's system between the Company's generating sources and the customers' meters. In addition, small, fractional amounts of energy either stolen (diversion) or not metered are included as system energy losses.

A discrepancy was identified in analyzing the purchases and sales data provided by the Company. Specifically, data reported in the response to Staff Data Request No 247 for the month of September 2006 resulted in a loss factor calculation for the twelve months ending June 2007 of 5.23% of Net System Input (NSI), which is abnormally low. In addressing this anomaly, Empire adjusted the data reported for September 2006 and reported a revised loss percentage for the twelve months ending June 2007 of 6.82% of NSI. For the same twelve month period, Staff calculated a loss factor of 6.78% of NSI after making its own adjustment to the data reported for September 2006. These line loss percentages compare well with the line loss percentage of 6.79% of NSI as listed in the most recent loss study, which is based on data from calendar year 2005, provided by Empire for its Missouri jurisdiction.

Therefore, Staff recommends adopting a line loss percentage of 6.79% of NSI. This loss percentage is being utilized by Staff witness Shawn E. Lange in developing loads used in Staff's fuel model. In addition, the aforementioned loss study is being used by Staff in its rate design and its consideration of a fuel adjustment clause.

Staff Expert: Alan J. Bax

<u>5. Planned and Forced Outages</u>

Planned and forced outages for most units were normalized by using the five year average of actual values taken from data supplied by Empire. Riverton 9, 10, 11 and State Line 1 outages were normalized by using a seven year average. Iatan 1 outages were normalized by using a six year average.

Staff Expert: Leon C. Bender

E. Depreciation

The Staff recommends the Company retain the currently ordered depreciation rates, as shown in Appendix 5. The Staff's recommendation not to change depreciation rates in this case follows the Commission's Report and Order in Case No. ER-2006-0314 that depreciation rates should not be changed when a company has the opportunity to book and collect additional amortization amounts. The Company's approved Stipulation and Agreement in Case No. EO-2005-0263 created a Regulatory Plan that established an amortization mechanism for Empire in any general rate case filed prior to the rate case that includes Iatan II investment and meets certain additional criteria. The current case, No. ER-2008-0093, falls under the terms of the Company's Regulatory Plan.

Staff Expert: Rosella L. Schad

F. Payroll and Benefits

1. FAS 87 and FAS 88 Pension Costs

The Staff, EDE and other parties entered into a Stipulation and Agreement in Case No. ER-2004-0570 titled, "Nonunanimous Stipulation and Agreement Regarding Pension Issues," which addressed the ratemaking treatment for annual pension cost under Financial Accounting Standard (FAS) 87. This agreement was modified by the stipulation and agreement titled "Stipulation and Agreement as to Certain Issues" entered into in Empire's last Missouri rate proceeding, Case No. ER-2006-0315.

These past agreements provide for Empire to have its pension rate allowance set equal to its most current annual level of pension expense as calculated under FAS 87. To the extent this pension amount is greater than its "minimum ERISA" annual pension funding requirement, then that excess amount is used to reduce Empire's Prepaid Pension Asset included in rate base. Further, these agreements also set up a "tracker mechanism" for Empire's pension expense, in which any excess or deficiency of its pension rate allowance compared to its ongoing levels of FAS 87 expense is treated as a regulatory asset or liability. The pension tracker regulatory asset or liability is then included in Empire's rate base, and amortized as an addition or reduction to pension expense over a five-year period. Pension cost under FAS 87 is reflected in the Staff's income statement in this case, Case No. ER 2008-0093, consistent with the ratemaking treatment agreed to in the stipulation and agreements the Commission approved in Empire's last two electric rate cases. EDE's rate base, as determined by the Staff, includes the unrecovered balance of the prior Prepaid Pension Asset and the FAS 87 Regulatory Asset which represents the difference between FAS 87 pension costs recovered in rates and FAS 87 pension costs recognized in the financial statements between rate cases.

Staff Expert: Dana E. Eaves

2. FAS 106 – Other Post Retirement Benefit Costs (OPEB's)

In Case No. ER-2006-0315 a document titled, "Stipulation and Agreement as to Certain Issues," addressed the ratemaking treatment for annual OPEB's cost under Financial Accounting Standard (FAS) 106. This stipulation and agreement was intended to ensure that the amount collected in rates for OPEBs costs is based on the FAS 106 cost recognized by the Company for financial reporting purposes, using a methodology similar to that used to determine FAS 87 pension cost in a stipulation from the prior rate case, No. ER-2004-0570. The 2006 stipulation also called for use of an OPEBs "tracker mechanism" to quantify the difference over time in the OPEBs rate allowance provided to the Company and its actual annual OPEBs expenses under FAS 106. In this case, the Staff has complied with the terms agreed to in the preceding case for ratemaking treatment of OPEBs costs by performing the following actions:

1. The Company's ongoing FAS 106 cost recognized in rates in this case is $1,285,859.

2. Empire has over-recovered its FAS 106 expense in rates compared to its actual level of expense since the Company's last rate case. The balance in the Regulatory Liability account at December 31, 2007, was $2,027,939 which is to be amortized over five years as a reduction to expense in the amount of ($405,588).

3. The amount to be included in rate base as a reduction is $2,027,939, as noted above.

Staff Expert: Dana E. Eaves

3. Supplemental Executive Retirement Plan (SERP)

Empire's SERP program is a pension limited to Empire's officers and executives. Unlike Empire's regular pension plan, this program is unfunded; i.e., payments to its beneficiaries are not pre-funded through trust mechanisms. The Staff has consistently taken the position that rate recovery for plans such as SERP should be based upon actual payments to beneficiaries, and not based upon SERP expense accruals booked by the Company.

The Staff reviewed EDE's recurring cash SERP payments for the last five years. Since the level of cash SERP payments has varied considerably over the previous five years, the Staff determined a five-year average of these payments would be appropriate for a normalized level.

The difference between test year booked expense and the five-year average amount of payouts is reflected in adjustment S-76.9.

Staff Expert: Dana E. Eaves

4. Payroll, Payroll Taxes and 401K Benefit Costs

The Staff has adjusted Empire's test year payroll expense to reflect an annualized level of payroll, payroll taxes and 401K benefit costs as of December 31, 2007, the endpoint of the test year update period ordered for this case by the Commission.

Base payroll was calculated by multiplying employee levels at December 31, 2007, by the then-current appropriate salary or wage rate to derive the annualized payroll cost. Overtime payroll for Empire was calculated based upon a five-year average. The Staff removed from its calculation of this average the overtime hours associated with the January 2007 ice storm and the overtime hours incurred by Empire personnel in helping AmerenUE deal with its ice storm situation in December 2006. After allocation between expense and construction, the adjustment for payroll was distributed by Federal Energy Regulatory Commission Uniform System of Accounts (FERC USOA) Accounts based upon the actual distribution experienced by Empire for the twelve months ending December 2007. The Staff's Accounting Schedule 10, Adjustments to the Income Statement, reflects approximately 50 adjustments, segrated by FERC USOA Accounts, to reflect the total adjustment required to restate the test year payroll to an annualized level as of December 31, 2007.

Payroll taxes and 401K benefit costs were annualized by applying a ratio developed based upon the test year results to the annualized payroll as of December 31, 2007. The adjustments for annualized payroll tax and 401 K benefit costs appear as S-76.8, S-84.2, S-84.3 and S-84.4 in the Staff's Accounting Schedule 10.

Staff Expert: Paula Mapeka

5. Incentive Compensation

In Empire's most recent Missouri rate case, Case No. ER-2006-0315, the Staff recommended a partial disallowance of annual incentive compensation tied to Empire's Management Incentive Compensation Plan (MIP), a discretionary compensation incentive award for salaried non-officer employees, as well a disallowance of a program that offers certain employees lump-sum payments in the nature of bonuses called "Lightning Bolts." The Commission adopted the Staff's recommendations on this matter. The Staff has disallowed portions of Empire's test year incentive compensation expenses in this case consistent with the Commission's Report and Order in Case No. ER-2006-0315.

a. MIP

In early 2007, MIP awards were paid to Empire senior officers for the achievement of goals during the calendar year 2006. Each senior officer had a list of goals pertaining to areas such as expense, customer service, regulatory performance, safety and reliability and financial performance. Each of these goals was given a specific performance measure and a weighting, thus assigning a target cash payout. The amount of the award determination was based upon attainment of a specific performance level by the senior officer:

Threshold (50% of target payout)
Target (100% target payout)
Maximum (200% of target payout)

If the results for a specific goal were below the threshold, the senior officer did not receive an MIP award related to that specific goal. If the results were at or above the level set for the maximum goal, the senior officer received double the target MIP award for that specific goal.

Related to the MIP, the Staff eliminated the recovery of awards related to the gas property transition, awards associated with meeting (but not exceeding) budgetary goals, and any awards related to attainment of earnings goals. In the Staff's view, since financial goals directly benefit shareholders, shareholders should bear the cost of these incentives.

b. Lightning Bolts

The Staff is recommending a disallowance of the cost of discretionary bonuses (Lightning Bolts), paid to employees consistent with its position in Empire's prior rate cases. The Commission's Report and Order in Case No. ER-2006-0315 adopted the Staff's recommended disallowance of short-term incentive compensation tied to discretionary bonuses that are unsupported by well defined goals and for which the criteria for granting awards is not known in advance.

c. Equity Incentive Compensation

In Empire's last rate case, Case No. ER-2006-0315, the Staff also recommended a disallowance of long-term stock incentive compensation awarded to Empire's executive management resulting in the issuance of Empire's stock and performance shares for achievement of goals. Stock options are considered part of the senior officer's total compensation and are granted each year to the officers of the Company. The senior officers do not have any specific goals to meet in order to be granted these stock options. The senior officer can exercise the options after a three year vesting period if the stock price is higher than at the time of the grant and the senior officer is still employed by the company. Achievement of these goals benefits Empire's shareholders, not Empire's ratepayers. Additionally, unlike other expense recognition in the income statement, expense recognition for equity-based incentive compensation will never result in a cash outlay by Empire. The Staff has eliminated equity compensation recognized as an expense in the test year.

Staff Expert: Paula Mapeka

G. Maintenance Normalization Adjustments

Empire's maintenance expenses for its generating facilities (production stations) tend to fluctuate from year to year, since unscheduled outages occur at irregular and unpredictable times, and major planned outages do not occur annually. Each maintenance account was reviewed and analyzed separately for each production station. The production facilities examined included Iatan, Asbury, Riverton, State Line Combined Cycle, State Line 1, and Energy Center 1 and 2. These units were examined individually because each of them was on a different maintenance cycle and to group them would have either overstated or understated the final annualized maintenance costs. These adjustments were then combined when possible in an effort to reduce the volume of adjustments. The cumulative value of all production maintenance adjustments is $551,065.

1. Iatan

The Staff noted that the Iatan production station is on a six-year major maintenance cycle. For that reason, the Staff used a six-year average of maintenance costs. Empire owns only 12% of the Iatan unit, with Kansas City Power & Light Company (KCPL) and Aquila owning the remainder.

2. Asbury

The Asbury maintenance expense is based on a five-year overhaul schedule of the boiler and turbine.

3. Riverton

The Riverton maintenance expense is based on a five-year overhaul schedule of the boiler and turbine The Staff's adjustment is based upon a five-year average of maintenance costs.

4. State Line Combined Cycle (SLCC)

Based upon the review of actual costs incurred by the Company under its contract with Siemens Westinghouse Power Corporation (Siemens) for the maintenance of the SLCC unit for the last five years, the Staff subtracted the amount of expenses incurred in the test year ended June 30, 2007, from the five-year average expenses to calculate the Staff's adjustment.

5. State Line 1 and Energy Center 1 and 2

Empire has had a contract with Siemens, related to the maintenance of these production units, since June 29, 2001. The terms of the contract require Siemens to conduct maintenance service for the turbines, which are required to run for a specified number of hours per year. If a turbine does not meet the hours requirement, a credit is due to Empire and, if the turbine exceeds the hours, then the Company incurs more costs. The nature of this expense varies greatly from year to year and, therefore, the Staff is recommending using a five-year average to normalize this expense. The actual test year amount is subtracted from the five year average, to derive the Staff's adjustment.

6. Riverton 12

As previously discussed, Empire's new Riverton 12 generating came online in April 2007. Without even a full year of operating history, the Staff cannot use historical analysis for this unit to include a reasonable level of maintenance cost for it in rates. For purposes of this case only, the Staff has accepted the Company's adjustment, sponsored by Empire witness Blake Mertens in his direct testimony, to include an estimated level of maintenance costs for the Riverton 12 unit in its case. The Staff's adjustment for Riverton 12 maintenance is S-28.2.
Staff Expert: Dana E. Eaves.

H. Other Non-Labor Expenses

1. Rate Case Expenses

The Staff has included the actual costs incurred by Empire as of December 31, 2007, for this rate case (Case No. ER-2008-0093). The Staff's rate case adjustment is based upon a two-year normalization.

Adjustment S-77.1 removes from FERC USOA Account 928, Regulatory Commission Expense, all expenses booked in the test year associated with prior Empire Missouri rate proceedings. The Staff has proposed a separate adjustments to add back normalized rate case costs to Account 928 (Adjustment Nos. S-77.2).

The exclusion of prior rate case expenses is appropriate because the Staff's policy is to recommend recovery in rates of normalized rate case expenses only on a prospective basis. The Staff believes it is inappropriate to allow specific recovery in rates of amounts related to past rate proceedings. The Staff will work with the Company through the duration of this case to establish a reasonable and ongoing normalized level of rate case expense for inclusion in rates. This means that any additional expenses associated with the processing of this rate filing by Empire will be examined to determine their appropriateness for inclusion in this case. This will allow costs such as consulting fees, employee travel expenditures and legal representation, which are directly associated with the length of the case through the settlement conference and hearing process, to be properly included in this rate case.

The Staff does not agree that rate case expense is an item that should be "amortized" in a rate case, as that implies an obligation to allow recovery of any unamortized costs in the utility's next rate proceeding.

Adjustment S-77.3 annualizes FERC expenses.

Adjustment S-77.4 is the Staff's annualized PSC assessment recommendation.

Adjustment S-77.5 normalizes the cost of a Commission ordered depreciation study over five years.

Staff Expert: Paula Mapeka

2. Dues and Donations

The Staff reviewed the list of membership dues paid, and donations made, to various organizations that Empire charged to its utility accounts during the test year. The Staff proposes adjustments to exclude various dues and donations that were included by Empire in its above-the-line expense accounts. Such dues and donations were excluded because they were not necessary for the provision of safe and adequate service, and thus do not have any direct benefit to ratepayers. Allowing the Company to recover these expenses through rates causes the ratepayer to involuntarily contribute to these organizations. Examples of dues excluded from recovery in the rate case are dues paid to the Rotary Club, Twin Hills Golf and Country Club, Christian County Fair, Bolivar Saddle Club, etc.

In *Re: Missouri Public Service, a Division of UtiliCorp United, Inc.*, Case Nos. ER-97-394, et al., Report and Order, 7 Mo.P.S.C.3d 178, 212 (1998), the Commission stated:

> The Commission has traditionally disallowed donations such as these. The Commission finds nothing in the record to indicate any discernible ratepayer benefit results from the payment of these donations. The Commission agrees with the Staff in that membership in the various organizations involved in this issue is not necessary for the provision of safe and adequate service to the MPS ratepayers.

Staff Expert: Paula Mapeka

3. Edison Electric Institute (EEI) Dues

According to information obtained from the Edison Electric Institute's (EEI's) website (www.eei.org), EEI is an association of investor owned electric utilities and industrial affiliates. From the information concerning EEI reviewed by the Staff in this case, it is clear that part of EEI's function is to represent the interests of the electric utility industry in the legislative and regulatory arenas. By necessity, this role includes engagement in lobbying activities by EEI.

In Case No. ER-83-49, a KCPL rate increase case, the Commission stated its position that EEI dues:

> ...would be excluded as an expense until the company could better quantify the benefit accruing to both the company's ratepayers and shareholders.

This position has been re-affirmed by the Commission in subsequent rate proceedings.

In *Re: Kansas City Power & Light Co.*, Case Nos. EO-85-185 et al., Report and Order, 28 Mo.P.S.C.(N.S.) 228, 259 (1986), the Commission stated:

> . . . The argument that allocation is not necessary if the benefits lessen the cost of service to the ratepayers by more than the cost of the dues, misses the point.
>
> It is not determinative that the quantification of benefits to the ratepayer is greater that the EEI dues themselves. The determining factor is what proportion of those benefits should be allocated to the ratepayer as opposed to the shareholder. It is obvious that the interests of the electric industry are not consistently the same as those of the ratepayers. The ratepayers should not be required to pay the entire amount of EEI dues if there is benefit accruing to the shareholders from EEI membership as well. The Commission finds this to be the case. The Company has been informed in prior rate cases that it must allocate its quantified benefits from membership in EEI. That has not been done herein. Therefore, no portion of EEI dues will be allowed in this case.

Pending receipt of information from Empire that would quantify ratepayer benefits from its participation in EEI, the Staff removed EEI dues from Empire's cost of service through adjustment S-79.3.

Staff Expert: Paula Mapeka

4. Insurance Expense

Insurance expense is the cost of protection obtained from third parties by utilities against the risk of financial loss associated with unanticipated events or occurrences. Utilities, like non-regulated entities, routinely incur insurance expense in order to minimize their liability (and, potentially, that of its customers) associated with unanticipated losses. The Staff proposed an adjustment to annualize Empire's insurance expense to reflect the premiums paid as of December 31, 2007, the end of the update period.

Staff Expert: Paula Mapeka

5. Tree Trimming

The Staff's analyzed data pertaining to Empire's tree trimming expenses over the years 1999-2007. Based upon its review, the Staff is proposing an adjustment to normalize the level of transmission and distribution tree trimming expense that should be included in customer rates.

Empire has included approximately $5,900,000 for tree trimming expense in its rate case filing. The Staff's adjustment annualized the Company's tree trimming expense to reflect expenses through the end of the update period. The Staff believes this represents a reasonable level of ongoing tree trimming expense for Empire. Both the Staff and Empire have removed from tree trimming expenses any amounts attributable to the January 2007 ice storm. These costs are considered extraordinary in nature and are being amortized to expense (see Section 15 below).

The Staff is aware that the Commission is promulgating a rule concerning vegetation management that, if adopted, will likely cause an increase in Empire's ongoing tree trimming expenditures. In the context of this rate case, the Staff is willing to discuss with Empire and other parties to this proceeding consideration of special regulatory mechanisms that would allow Empire the opportunity for rate recovery of higher levels of tree trimming expense than it has incurred in the past, in light of the proposed rulemaking before the Commission. These mechanisms would include a "tracker" mechanism similar to that agreed to for AmerenUE for tree trimming costs in its last rate proceeding, Case No. ER-2007-0002.

Staff Expert: Amanda C. McMellen

6. Customer Deposit Interest Expense

See the discussion in Section VI.H., Rate Base-Customer Deposits.

Staff Expert: Paula Mapeka

7. Property Tax Expense

For property assessment purposes, utility companies are required to file with their respective taxing authorities a valuation of its utility property at the beginning of each assessment year, which is January 1st. Several months later, based on the information provided by the utility, the taxing authority will in turn send the company what is known as "assessed values" for every category of the company's property. The taxing authority will issue to the utility company a property tax rate later in the year. The final step in the process is when the taxing authority issues a property tax bill to the company late in each calendar year with a "due date" of December 31. The billed amount of property taxes is based on the property tax rate applied to the previously determined assessed values of the utility's plant in service balances as of January 1 of the same year.

Adjustment S-84.1 annualizes Empire's property tax expense. This adjustment was calculated by developing a property tax rate to be applied to total electric plant in service at December 31, 2007. To develop the property tax rate, the Staff divided the amount of total property taxes due in calendar years 2003 - 2007 by the total plant in service for each year on January 1, 2003 to January 1, 2007. This property tax rate was then applied to total electric plant in service on December 31, 2007, to arrive at annualized property taxes. The annualized property tax expense was then subtracted from test year property tax expense to derive the adjustment. The Staff believes that the property tax expense arrived at in this manner is the best estimate available of ongoing levels of these taxes, and is consistent with how property taxes have been calculated for rate purposes in the past for Empire and other Missouri utilities.

Staff Expert: Paula Mapeka

8. Bad Debt Expense

Bad debt expense is the portion of retail revenues that Empire is unable to collect from retail customers by reason of bill non-payment. After a certain amount of time has passed, delinquent customer accounts are written off and turned over for collection; Empire is subsequently successful in collecting some portion of the delinquent amounts owed. The Staff calculated the bad debt rate by examining the actual five-year (2003-2007) history of billed revenues that were never collected (net write-offs). After analyzing the data, it was apparent that there is an upward trend in this item. From the information provided for the update period through December 31, 2007, a bad debt percentage was derived, which was then applied to the Staff's annualized level of retail revenues to obtain the annualized level of bad debt expense. The Staff's adjustment for bad debt expense, S-62.1, adjusts the test year results to reflect a level of bad debt expense that is consistent with the Staff's annualized level of retail revenue.

Staff Expert: Amanda C. McMellen

9. Advertising Expense

In forming its recommendation of the allowable level of Empire's advertising expense, the Staff relied on the principles the Commission relied upon in the 1986 Kansas City Power & Light Company rate case. In *Re: Kansas City Power and Light Company*, Case Nos. EO-85-185, et al., 28 Mo. P.S.C. (N.S.) 228, 269-71 (1986), the Commission adopted an approach that classifies advertisements into five categories and provides separate rate treatment for each category. The five categories of advertisements recognized by the Commission therein are as follows:

1. General: informational advertising that is useful in the provision of adequate service;

2. Safety: advertising which conveys the ways to safely use electricity and to avoid accidents;

3. Promotional: advertising used to encourage or promote the use of electricity;

4. Institutional: advertising used to improve the company's public image;

5. Political: advertising associated with political issues.

The Commission adopted these categories of advertisements because it believed that a utility's revenue requirement should: 1) always include the reasonable and necessary cost of general and safety advertisements; 2) never include the cost of institutional or political advertisements; and 3) include the cost of promotional advertisements only to the extent that the utility can provide cost-justification for the advertisement (Report and Order in KCPL Case Nos. EO-85-185, et al., 28 Mo.P.S.C. (N.S.) 228, 269-271 (April 23, 1986)).

Accordingly, in the current rate case, the Staff has proposed an adjustment to exclude the costs of institutional and promotional advertising from recovery in rates. (The Staff found no evidence that Empire engaged in any political advertising.) Costs for safety advertising and general advertising directed towards the benefit of existing customers were unadjusted by the Staff. Also, Empire conducts a customer opinion survey analysis almost every two years with the last three such surveys having been conducted in 2002, 2004 and 2006. In this case, the Staff proposed an adjustment to normalize the test year customer opinion survey costs over two years. The advertising and customer survey adjustments are S-66.1, S-79.4, and S-71.3.

Staff Expert: Paula Mapeka

10. Postage

Empire provided the Staff with the customer numbers and the amounts of monthly postage expense for 2006 and 2007. Adjustment S-61.3 reflects the postal increase that went into effect on May 14, 2007.

Staff Expert: Paula Mapeka

11. Outside Services

Various outside (independent) contractors and vendors provide legal, auditing and other services to Empire to assist the Company in carrying out its operational activities only as needed. The Staff reviewed Empire's test year outside services expense booked to FERC USOA Accounts 923.005 through 923.514. The Staff normalized the amounts of outside services on a going forward basis by calculating a five-year average of incurred costs for these accounts.

Staff Expert: Paula Mapeka

12. Injuries and Damages and Workers' Compensation

The workers' compensation adjustment annualizes this expense based upon the premiums in effect at December 2007 to reflect an ongoing and normal expense level for Empire.

For injuries and damages, the Staff used a three-year average of actual injuries and damages payments to normalize this cost. A three-year average of payments was used as representative of injuries and damages costs because a historical analysis shows a considerable fluctuation in the payments. Actual injuries and damages payouts were used in the Staff's adjustment, as opposed to Empire's expense accruals, as the Staff contends that this expense should be recognized in rates based upon actual cash payments, and not on the Company's estimates of future injuries and damages payouts.

Staff Expert: Paula Mapeka

13. Employee Benefits

Empire currently offers its employees Dental & Vision, Healthcare and Life Insurance benefits. The Staff performed an analysis of the employee benefit costs included in FERC USOA Account 926 from the general ledger. The Dental & Vision plan is a new plan and was implemented in early 2007. The Staff annualized this expense by including the expense associated with the update period, which annualizes these expenses to reflect a full twelve months. The Staff's analysis also shows that healthcare expenses and life insurance are currently increasing slightly at Empire. The Staff annualized the expense of employee healthcare and life insurance plans in effect through the update period ending December 31, 2007. This amount was compared to the test year level to determine the adjustment.

Staff Expert: Amanda C. McMellen

<u>14. Franchise Taxes</u>

The Staff has eliminated the franchise taxes (otherwise known as gross receipt taxes) from Empire's expense; as such taxes are merely a pass-through item to Empire. Empire bills and collects the taxes from its customers, and then in turn passes the taxes on to the municipal taxing authorities. The Staff has also proposed an adjustment in an identical amount to remove franchise taxes from Empire's test year revenues, so that these taxes have no effect on the Company's revenue requirement. The adjustment to revenues is S-1.10, and the adjustment to eliminate this item from expense is S.84.5.

<u>15. Amortization Expense</u>

a. Amortization of Electric Plant

The Staff analyzed all amortization expense booked to FERC USOA Account 404.000, Amortization–Limited Term Electric Plant. The Staff's adjustment increased expense to reflect the annualized amortization based on updated information through December 31, 2007, (as described earlier in Section VI.G.).

b. Amortization of Stock Issuance Costs

In 2003, 2004, 2006 and 2007, Empire made additional issuances of common equity, with the issuance in 2007 worth approximately $80,000,000. In making all of these issuances, the Company incurred costs totaling $5,563,125. It is the Staff's position that these costs be recovered through rates as an above-the-line adjustment to operating expenses. The Staff proposes that these costs be amortized over a five-year period for purposes of this proceeding.

c. Amortization of Demand-Side Management Costs – Regulatory Asset

The Demand-Side Management (DSM) USOA Account 182.318 contains costs for DSM programs that are in various stages of development and implementation. Based on the Staff's participation in the Customer Programs Collaborative (CPC) established to advise Empire in the development of DSM programs and the Staff's review of the costs in Account 182.318, the Staff has amortized the previously mentioned amounts over ten years in accordance with the process agreed to in the Empire Regulatory Plan Stipulation and Agreement (Case No. EO-2005-0263). The DSM costs include the payments to Empire's customers that participate in the programs.

d. Amortization of Ice Storm Costs

In January 2007, a major winter storm that featured damaging freezing rain and heavy ice accumulation hit the Company's service area. Significant damage was caused to Empire's transmission and distribution systems. The restorative repairs were too extensive for Empire employees to handle on their own. So, the Company hired various contractors and employees from other utilities to assist in the restoration efforts. Empire tracked all costs associated with the ice storm separately. Some of these costs were capitalized and have been included in Empire's plant in service balances. For the amounts that were not capitalized, the Company is requesting in this case that these expenses be amortized over five years. The Company is also requesting that the remaining unamortized balance of the ice storm expenses be included in rate base as a regulatory asset.

The Staff agrees with Empire that the costs incurred for the January 2007 ice storm are significant and extraordinary. The Staff has amortized the amounts to expense over a five-year period. Consistent with past practice, the Staff recommends that this amortization begin within a reasonable time after the extraordinary expenses are incurred, and accordingly suggests a start date for the amortization of April 2007. Therefore, this amortization should end on Empire's books as of March 2012. The Staff notes that it is not appropriate to delay the beginning of an extraordinary event amortization to the date new rates are allowed the affected utility, as such treatment will almost certainly guarantee the utility over-recovery of the deferred costs in rates. Also consistent with past Commission practice, the Staff opposes inclusion of the unamortized portion of extraordinary event deferrals in rate base. Utility shareholders and customers should share in the risk that such events occur, and denying rate base treatment to these deferred costs will cause Empire to share in a portion of these costs (i.e., the time-value of money associated with rate recoveries from customers over a five-year period).

Staff Expert: Amanda C. McMellen

e. Regulatory Plan Amortization

Because Empire did not begin collecting the regulatory plan amortization amount in rates authorized by the Commission until January 1, 2007, only one-half of this annual allowance was received by Empire in the test year for this case ending June 30, 2007. For this reason, the Staff has adjusted Empire's amortization expense to reflect a full year of its current regulatory plan amortization in the Staff's expenses. For ease of presentation, the Staff removed the amount of regulatory plan amortizations included in Empire's test year depreciation expense, and then adjusted amortization expense to reflect a full year of these amortizations in the Staff's case.

Staff Expert: Mark L. Oligschlaeger

16. Demand Side Management Costs

There are currently five DSM programs in place at Empire. The programs are as follows: Weatherization Program, Change a Light Program, Low-Income New Home Program, the High Efficiency Residential Central Air Conditioning Rebate Program (CAC) and the Industrial Facility Rebate Program (C&I Rebate). For a description of the individual programs currently in place and in development, please see page 3 of the direct testimony of Empire witness Sherrill L. McCormack. These programs were created as a result of the Stipulation and Agreement in Case No. EO-2005-0263, Empire's Regulatory Plan case. All actual costs incurred for the new programs since the CPC was created have been included in expenses.

In Empire's last rate case, it was discovered that some funding from the Company's DSM programs before the CPC was created was not being used. So, all balances for the unused funds associated with the previous DSM programs, before the CPC was created, are eliminated from the test year by both Empire and the Staff.

Staff Expert: Amanda C. McMellen

a. Experimental Low Income Program

Staff agrees with Empire witness Sherrill L. McCormack that Empire's Experimental Low Income Program (ELIP) should be modified. This "experimental" program, which provides monthly bill credits to customers with household income of 125% of the Federal Poverty Level or less, began in 2003. An evaluation of this program was conducted in 2006, and the program changed as a result of the Commission's order in ER-2006-0315, Empire's last rate case.

It is time that this program is either made permanent or discontinued. It is Staff's position that the program should be continued as the Low-Income Customer Assistance Program (LICAP), as Ms. McCormack recommends, with just two modifications.

Staff supports Ms. McCormack's recommendation to fund LICAP at $150,000 a year. Staff first modification relates to the source of the funding. Since the program has never been shown to be cost effective for the ratepayer, Staff recommends that the program continue to be funded by both the ratepayers ($75,000) and the shareholders ($75,000) rather than being completely funded by ratepayers as proposed by Ms. McCormack.

The second modification that Staff recommends is that the arrearage repayment incentive be removed from the program, since no customers have utilized it since this feature. The arrearage repayment incentive was one of the changes to the program resulting from the Commission's order in ER-2006-0315.

Staff agrees that the unused ELIP funds collected from the customers since 2003 should be returned to the ratepayers. However, Staff recommends that this be achieved by reducing Empire's rate base by the amount the unused funds. Staff's rate base reflects this treatment.

Ms. McCormack recommends re-titling the program as the Low-Income Customer Assistance Program (LICAP), and Staff agrees with that proposal.

Staff Expert: Lena M. Mantle

17. Miscellaneous Adjustments

There were several adjustments that were required to be made to certain of Empire's 2006 income statement accounts to remove the effects of credits that were made to record expenses as regulatory assets, remove nonrecurring revenue and expenses and for other reasons. Both Empire and the Staff made these adjustments. These adjustments include:

Adjustment S-28.3	OPSA Amortization
Adjustment S-86.1	Eliminate Loss on Energy Center Disallowance

Staff Expert: Amanda C. McMellen

J. Current and Deferred Income Tax

1. Current Income Tax

Current income tax has been calculated generally consistent with the methodology used in Empire's most recent Missouri rate case, Case No. ER-2006-0315. A new tax deduction is reflected for Empire's production costs. A tax timing difference occurs when the timing used in reflecting a cost (or revenue) for financial reporting purposes is different than the timing required by the Internal Revenue Service (IRS) in determining taxable income. Current income tax reflects timing differences consistent with the timing required by the IRS. The tax timing differences used in calculating taxable income for computing current income tax are as follows:

Add Back to Operating Income Before Taxes:

Book Depreciation Expense

Non-Deductible Expenses

Contribution in Aid of Construction

Regulatory Plan Amortizations

Subtractions from Operating Income:

Interest Expense – Weighted Cost of Debt X Rate Base

Tax Straight-Line Depreciation

Tax Depreciation-Excess

2. Deferred Income Tax Expense:

When a tax timing difference is reflected for ratemaking purposes consistent with the timing used in determining taxable income for current income tax due the Internal Revenue Code (IRC), the timing difference is given "flow-through" treatment. When a current year timing difference is deferred and recognized for ratemaking purposes consistent with the timing used in calculating pre-tax operating income in the financial statements, then that timing difference is given "normalization" treatment for ratemaking purposes. Deferred income tax expense for a regulated utility reflects the tax impact of "normalizing" tax timing differences for ratemaking purposes. IRS rules for regulated utilities require normalization treatment for the timing difference related to accelerated tax depreciation.

The "Nonunanimous Stipulation and Agreement Regarding Regulatory Plan Amortizations" in Case No. ER-2006-0315 regarding the Regulatory Plan Additional Amortization requires that the additional amortization be included in the straight-line tax depreciation amount used in normalizing the timing difference for accelerated tax depreciation. The Staff's deferred income tax calculation treats the Regulatory Plan Additional Amortization, approved in Case No. ER-2006-0315, as an increase in the straight-line tax depreciation deduction, consistent with the "Nonunanimous Stipulation and Agreement Regarding Regulatory Plan Amortizations" approved in Case No. ER-2006-0315.

Staff Expert: Amanda C. McMellen

IX. Regulatory Plan Amortizations

In Case No. EO-2005-0263, the Commission approved a "regulatory plan" for Empire, which featured several provisions intended to protect Empire's investment grade credit ratings during its period of projected heavy construction from 2005 through 2010, when the Iatan II generating unit is constructed and projected to come on-line. One of the more significant features of the Empire regulatory plan is the reflection of special "amortizations" in rates if the Company does not meet certain financial ratios in any general rate case filed prior to the rate case that reflects Empire's planned investment in the Iatan II unit. The Iatan II case is planned for 2010. The background for the regulatory plan amortization mechanism is discussed in more detail in the direct testimony of Staff witness Mark L. Oligschlaeger.

Appendix D to the Stipulation and Agreement in Case No. EO-2005-0263 sets out the format under which the Empire regulatory plan amortization calculations are to be made. The Staff has followed this format in this case and in Empire's most recent prior rate case, Case No. ER-2006-0315. The Staff's amortization calculation for this proceeding is attached to this report as Appendix 6. With one exception, the Staff's methodology in its regulatory plan amortization calculations is identical to that which was used by the Staff in Case No. ER-2006-0315. This exception is described below.

The modification in this case to the Staff's prior amortization calculation for Empire has to do with Empire's Trust-Owned Preferred Stock (TOPRS) financing. TOPRS are considered a "hybrid" security, having attributes of both debt and equity. In Case No. ER-2006-0315, the Staff treated TOPRS as being 100% debt related. Since that time, the Staff has determined that Standard & Poor's consider securities like TOPRS to be 50% debt equivalents (i.e., half debt and half equity). Thus, in this regulatory plan amortization calculation, the Staff has treated Empire's TOPR balance as being 50% debt related.

In this case, Appendix 6 shows that an additional amoritzation should be added to Empire's traditional revenue requirement to determine its total rate increase amount, based on its adjusted financial results at year-end 2007. The amount of the additional amortization can be found at Line 90 of Appendix 6.

X. Fuel Adjustment Clause (FAC)

In the recent Aquila rate case, Case No. ER-2007-0004, the Commission utilized the following criteria for approval of a fuel adjustment charge (FAC):

1. Fuel and purchased power costs must be a significant portion of the utility's costs;
2. Fuel and purchased power costs must fluctuate significantly; and
3. Fuel and purchased power costs are outside the utility's control.

Table LM1 shows a comparison of the generation resources (including purchased power) by fuel type from the Staff's final fuel runs for (1) Union Electric Company, d/b/a AmerenUE (AmerenUE) in its recent rate case, Case No. ER-2007-0002, where the Commission did not allow a FAC; (2) Aquila in its recent rate case, where the Commission did allow a FAC: and, (3) Staff's direct testimony for Empire in this case:

Table LM1

AmerenUE

	MWh	Dollars
Coal	76.9%	81.1%
Nuclear	18.7%	6.6%
Natural Gas	0.6%	3.5%
Purchased Power	3.9%	8.8%

Aquila

	MWh	Dollars
Coal	67.5%	42.5%
Natural Gas	1.0%	3.8%
Purchased Power (Contract)	17.9%	13.3%

Purchased Power (Spot)	13.7%	40.4%

Empire

	MWh	Dollars
Coal	42.3%	24.7%
Natural Gas	19.0%	38.1%
Purchased Power (Contract)	30.9%	22.0%
Purchased Power (Spot)	7.8%	15.2%

Review of this information shows that Empire meets a greater percentage of its needs with gas-fired generation and spot purchased power than either AmerenUE or Aquila does. In fact, over half of Empire's fuel and purchased power costs consist of natural gas and spot purchased power costs.

Since the cost of natural gas and spot purchased power costs have fluctuated significantly in the past and are expected to continue to be volatile, and these costs are to a large part outside of Empire's control, Staff recommends the Commission approve a FAC for Empire.

A total pass through of all of Empire's fuel and purchased power costs would essentially shift the risk of price fluctuations and volatility entirely to the ratepayers. An appropriate way to ensure Empire retains an incentive to minimize fuel and purchased power costs is to not allow a 100% pass through of those costs. To get an estimate of the impact of various percentage pass-throughs, Staff reviewed the normalized fuel and purchased power costs of Empire for 2002, 2004 and 2006 as estimated by the Staff in Case Nos. ER-2002-0424, ER-2004-0570, and ER-2006-0315. Using these fuel and purchased power costs, Staff estimates that Empire absorbed approximately $85.5 million of fuel and purchased power costs between rate cases. For purposes of this analysis, Staff assumed a FAC for Empire for the four years 2003 through 2006 with the base fuel and purchased power costs being the costs for 2002. Table LM2 shows the amounts that would have been charged to ratepayers and the amounts that would have been absorbed by Empire for this time period for different percentage pass-throughs:

Table LM2

Sample Cost Allocation for FAC

% Recovered in FAC	$ Recovered from Ratepayers	$ Absorbed by EDE
100	$139,402,328	$0
95	132,432,212	6,970,116
90	125,462,095	13,940,233
85	118,491,979	20,910,349
80	111,521,862	27,880,466
75	104,551,746	34,850,582
70	97,581,630	41,820,698
65	90,611,513	48,790,815
60	83,641,397	55,760,931
55	76,671,280	62,731,048
50	69,701,164	69,701,164
45	62,731,048	76,671,280
40	55,760,931	83,641,397
35	48,790,815	90,611,513
30	41,820,698	97,581,630
25	34,850,582	104,551,746
20	27,880,466	111,521,862
15	20,910,349	118,491,979
10	13,940,233	125,462,095
5	6,970,116	132,432,212
0	0	139,402,328

Table LM2 shows that the $85.5 million that Staff estimated Empire actually absorbed during this time period equates to allowing about 40% of the fuel and purchased power costs to flow through a FAC to the ratepayers. Any pass-through greater than 40% would shift more of the fuel and purchased power risks to the ratepayers than they had without a FAC in place. At an approximate 40% pass-through, Empire would have the same risk that it did without an FAC. This also shows that if a FAC had allowed less than 40% cost recovery by Empire, the Company would have absorbed more than the $85.5 million in increased fuel and purchased power costs it absorbed without a FAC.

As a result of this analysis, Staff recommends that as an incentive to minimize fuel and purchased power costs, the FAC should permit Empire to recover and retain between 60% and

80% of the change in the fuel and purchased power costs. At the 60% level, Empire would be taking more fuel and purchased power risk but would also allow Empire to keep a significant portion of any dollar that it saves. At 80% a much greater risk of changes in fuel and purchased power costs is passed on to the ratepayers and much less on Empire, but Empire also has less incentive to control and reduce its fuel and purchased power costs. Staff recommends a 70% recovery of costs as a mid-point where, under a FAC, ratepayers take on a significant portion of the fuel and purchased power risk but Empire, by keeping 30% of the fuel costs it saves, still has an incentive to control and reduce fuel and purchased power costs.

Staff agrees that Missouri historical fuel and purchased power expenses recorded in FERC accounts 501, 509, 547, and 555 should be recovered through a FAC, excluding capacity charges associated with purchased power contracts recorded in FERC account 555. Since emission allowance costs are recorded in FERC account 509, Staff also recommends that the FAC include emission allowances revenues recorded in FERC account 254.103.

Rate design aspects, including the length and timing of the FAC accumulation and recovery periods, will be filed in Staff's later Rate Design report.

Staff Expert: Lena M. Mantle

Appendices:

Appendix 1: Staff Credentials

Appendix 2: Support for Staff Cost of Capital Recommendation

Appendix 3: Riverton 12 In-service Criteria

Appendix 4: Revenue Summary Sheet

Appendix 5: Staff Recommended Depreciation Rates

Appendix 6: Staff Regulatory Plan Amortization Calculation

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri's Application for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2008-0093

AFFIDAVIT OF MATTHEW J. BARNES

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Matthew J. Barnes, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in page(s) 5 - 17; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Matthew J. Barnes

Matthew J. Barnes

Subscribed and sworn to before me this 21st day of February, 2008.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
County of Cole
My Commission Exp. 07/01/2008

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the matter of The Empire District Electric Company of Joplin, Missouri's application for authority to file tariffs increasing rates for electric service provided to customers in the Missouri service area of the Company)	Case No. ER-2008-0093

AFFIDAVIT OF ALAN J. BAX

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Alan J. Bax, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in page(s) 39 and 40; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Alan J. Bax
Alan J. Bax

Subscribed and sworn to before me this 21st day of February, 2008.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

Susan L. Sundermeyer
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the matter of The Empire District Electric Company of Joplin, Missouri's application for authority to file tariffs increasing rates for electric service provided to customers in the Missouri service area of the Company	))))))	Case No. ER-2008-0093

AFFIDAVIT OF DANIEL I. BECK

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Daniel I. Beck, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in page(s) 21; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Daniel I. Beck

Daniel I. Beck

Subscribed and sworn to before me this 21st day of February, 2008.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

Susan L. Sundermeyer

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the matter of The Empire District Electric Company of Joplin, Missouri's application for authority to file tariffs increasing rates for electric service provided to customers in the Missouri service area of the Company	))))))	Case No. ER-2008-0093

AFFIDAVIT OF LEON C. BENDER

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Leon C. Bender, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in page(s) 35-38 and 40; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Leon C. Bender

Leon C. Bender

Subscribed and sworn to before me this 21st day of February, 2008.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

Susan L. Sundermeyer

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri's Application for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2008-0093

AFFIDAVIT OF DANA E. EAVES

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Dana E. Eaves, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in page(s) 19, 20, 32-37, 41-43, 45 and 46 ; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Dana E. Eaves

Dana E. Eaves

Subscribed and sworn to before me this 21st day of February, 2008.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
County of Cole
My Commission Exp. 07/01/2008

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the matter of The Empire District Electric Company of Joplin, Missouri's application for authority to file tariffs increasing rates for electric service provided to customers in the Missouri service area of the Company	))))))	Case No. ER-2008-0093

AFFIDAVIT OF DAVID ELLIOTT

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

David Elliott, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in page(s) 17 and 18; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

David Elliott

Subscribed and sworn to before me this 21st day of February, 2008.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

Susan L. Sundermeyer
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the matter of The Empire District Electric Company of Joplin, Missouri's application for authority to file tariffs increasing rates for electric service provided to customers in the Missouri service area of the Company	))))))	Case No. ER-2008-0093

AFFIDAVIT OF MANISHA LAKHANPAL

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Manisha Lakhanpal, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in page(s) 27, 28, 30 and 31 ; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Manisha Lakhanpal
Manisha Lakhanpal

Subscribed and sworn to before me this 21st day of February, 2008.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

Susan L. Sundermeyer
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the matter of The Empire District Electric Company of Joplin, Missouri's application for authority to file tariffs increasing rates for electric service provided to customers in the Missouri service area of the Company	))))))	Case No. ER-2008-0093

AFFIDAVIT OF SHAWN E. LANGE

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Shawn E. Lange, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in page(s) 26, 27, 29, 38 and 39; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Shawn E. Lange
Shawn E. Lange

Subscribed and sworn to before me this 21st day of February, 2008.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

Susan L. Sundermeyer
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the matter of The Empire District Electric Company of Joplin, Missouri's application for authority to file tariffs increasing rates for electric service provided to customers in the Missouri service area of the Company	))))))	Case No. ER-2008-0093

AFFIDAVIT OF ERIN L. MALONEY

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Erin L. Maloney, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in page(s) 23; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Erin L. Maloney

Erin L. Maloney

Subscribed and sworn to before me this 21st day of February, 2008.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

Susan L. Sundermeyer
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the matter of The Empire District Electric Company of Joplin, Missouri's application for authority to file tariffs increasing rates for electric service provided to customers in the Missouri service area of the Company	))))))	Case No. ER-2008-0093

AFFIDAVIT OF LENA M. MANTLE

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Lena M. Mantle, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in page(s) 56, 57, 60 and 63; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Lena M Mantle
Lena M. Mantle

Subscribed and sworn to before me this 21st day of February, 2008.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

Susan L Sundermeyer
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri's Application for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2008-0093

AFFIDAVIT OF PAULA MAPEKA

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Paula Mapeka, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in page(s) 18, 21, 43-45 and 47-53; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Mapeka
Paula Mapeka

Subscribed and sworn to before me this 21st day of February, 2008.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
County of Cole
My Commission Exp. 07/01/2008

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri's Application for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2008-0093

AFFIDAVIT OF AMANDA C. MCMELLEN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Amanda C. McMellen, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in page(s) 20, 22-24, 30-32, 34 and 49-59; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Amanda C McMellen

Amanda C. McMellen

Subscribed and sworn to before me this 21st day of February, 2008.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
County of Cole
My Commission Exp. 07/01/2008

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the matter of The Empire District Electric Company of Joplin, Missouri's application for authority to file tariffs increasing rates for electric service provided to customers in the Missouri service area of the Company)	Case No. ER-2008-0093

AFFIDAVIT OF DAVID C. ROOS

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

David C. Roos, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in page(s) 29; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

David C. Roos

Subscribed and sworn to before me this 19th day of February, 2008.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri's Application for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)))))	Case No. ER-2008-0093

AFFIDAVIT OF ROSELLA L. SCHAD, P.E., C.P.A.

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Rosella L. Schad, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in page(s) 40 - 41; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Rosella L. Schad
Rosella L. Schad

Subscribed and sworn to before me this 21st day of February, 2008.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
County of Cole
My Commission Exp. 07/01/2008

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the matter of The Empire District Electric Company of Joplin, Missouri's application for authority to file tariffs increasing rates for electric service provided to customers in the Missouri service area of the Company	))))))	Case No. ER-2008-0093

AFFIDAVIT OF MICHAEL E. TAYLOR

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Michael E. Taylor, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in page(s) 17; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Michael E. Taylor
Michael E. Taylor

Subscribed and sworn to before me this 21st day of February, 2008.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

Susan L. Sundermeyer
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the matter of The Empire District Electric Company of Joplin, Missouri's application for authority to file tariffs increasing rates for electric service provided to customers in the Missouri service area of the Company	))))))	Case No. ER-2008-0093

AFFIDAVIT OF CURT WELLS

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Curt Wells, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in page(s) 28, 29, 31 and 32; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Curt Wells

Curt Wells

Subscribed and sworn to before me this 21st day of February, 2008.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

Susan L. Sundermeyer

Notary Public

APPENDIX I

STAFF CREDENTIALS

MATTHEW J. BARNES

I am currently employed as a Utility Regulatory Auditor III for the Missouri Public Service Commission (Commission). I accepted the position of Utility Regulatory Auditor I in June 2003 and have since been promoted.

Previously, I was employed by the Missouri Department of Natural Resources (MDNR). Prior to MDNR I was employed by the Missouri Department of Conservation as an Auditor Aide.

I have earned a Bachelor of Science degree in Business Administration with an emphasis in Accounting from Columbia College in December 2002. I earned a Masters in Business Administration with an emphasis in Accounting from William Woods University in May 2005.

SUMMARY OF CASE PARTICIPATION

Date Filed	Issue	Case Number	Exhibit	Case Name
10/6/2006	Rate of Return/ Cost of Capital	ER20060314	Surrebuttal	Kansas City Power & Light Company
9/8/2006	Rate of Return	ER20060314	Rebuttal	Kansas City Power & Light Company
9/13/2006	Rate of Return	GR20060387	Direct	Atmos Energy Corporation
10/15/2004	Rate of Return	TC20021076	Supplemental Direct	BPS Telephone Company
11/7/2006	Rate of Return	ER20060314	True-Up	Kansas City Power & Light Company
11/7/2006	Cost of Capital	ER20060314	True-Up	Kansas City Power & Light Company

Date Filed	Issue	Case Number	Exhibit	Case Name
8/8/2006	Rate of Return	ER20060314	Direct	Kansas City Power & Light Company
11/13/2006	Rate of Return	GR20060387	Surrebuttal	Atmos Energy Corporation
3/8/2006	Transaction Structure	TM20060272	Rebuttal	Alltel Missouri, Inc.
1/12/2007	Rate of Return	WR20060425	Surrebuttal	Algonquin Water Resources of Missouri LLC
12/28/2006	Rate of Return	WR20060425	Rebuttal	Algonquin Water Resources of Missouri LLC
12/1/2006	Rate of Return	WR20060425	Direct	Algonquin Water Resources of Missouri LLC
11/15/2005	Transaction Structure	IO20060086	Rebuttal	Sprint Nextel Corporation
11/13/2006	Rate of Return	GR20060387	Rebuttal	Atmos Energy Corporation
05/04/07	Rate of Return	GR20070208	Direct	Laclede Gas Company

Credentials of Alan J. Bax

I graduated from the University of Missouri - Columbia with a Bachelor of Science degree in Electrical Engineering in December 1995. Concurrent with my studies, I was employed as an Engineering Assistant in the Energy Management Department of the University of Missouri – Columbia from the Fall of 1992 through the Fall of 1995. Prior to this, I completed a tour of duty in the United States Navy, completing a course of study at the Navy Nuclear Power School and a Navy Nuclear Propulsion Plant. Following my graduation from the University of Missouri - Columbia, I was employed by The Empire District Electric Company (Empire) as a Staff Engineer until August 1999, at which time I began my employment with the Staff of the Missouri Public Service Commission (Staff). I am a member of the Institute of Electrical and Electronic Engineers. (IEEE).

TESTIMONY AND REPORTS FILED
BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION
BY ALAN J. BAX

COMPANY	CASE NUMBER
Aquila Networks – MPS	ER-2004-0034
Union Electric Company d/b/a AmerenUE	EO-2004-0108
Empire District Electric Company	ER-2002-0424
Kansas City Power and Light	EA-2003-0135
Union Electric Company d/b/a AmerenUE	EO-2003-0271
Aquila Networks – MPS	EO-2004-0603
Union Electric Company d/b/a AmerenUE	EC-2002-0117
Three Rivers and Gascosage Electric Coops	EO-2005-0122
Union Electric Company d/b/a AmerenUE	EC-2002-1
Empire District Electric Company	ER-2001-299
Aquila Networks – MPS	EA-2003-0370
Union Electric Company d/b/a AmerenUE	EW-2004-0583
Union Electric Company d/b/a AmerenUE	EO-2005-0369
Trigen Kansas City	HA-2006-0294
Union Electric Company d/b/a AmerenUE	EC-2005-0352
Missouri Public Service	ER-2001-672
Aquila Networks – MPS	EO-2003-0543
Macon Electric Coop	EO-2005-0076
Aquila Networks – MPS	EO-2006-0244
Union Electric Company d/b/a AmerenUE	EC-2004-0556
Union Electric Company d/b/a AmerenUE	EC-2004-0598
Empire District Electric Company	ER-2004-0570
Union Electric Company d/b/a AmerenUE	EC-2005-0110
Union Electric Company d/b/a AmerenUE	EC-2005-0177
Union Electric Company d/b/a AmerenUE	EC-2005-0313
Empire District Electric Company	EO-2005-0275
Aquila Networks – MPS	EO-2005-0270
Union Electric Company d/b/a AmerenUE	EO-2006-0145
Aquila Networks – MPS	ER-2005-0436
Union Electric Company d/b/a AmerenUE	EO-2006-0096

Daniel I. Beck, P.E.
Supervisor of the Engineering Analysis Section of the Energy Department
Utility Operations Division

Missouri Public Service Commission
P.O. Box 360
Jefferson City, MO 65102

I graduated with a Bachelor of Science Degree in Industrial Engineering from the University of Missouri at Columbia. Upon graduation, I was employed by the Navy Plant Representative Office in St. Louis, Missouri as an Industrial Engineer. I began my employment at the Commission in November, 1987, in the Research and Planning Department of the Utility Division (later renamed the Economic Analysis Department of the Policy and Planning Division) where my duties consisted of weather normalization, load forecasting, integrated resource planning, cost-of-service and rate design. In December, 1997, I was transferred to the Tariffs/Rate Design Section of the Commission's Gas Department where my duties include weather normalization, annualization, tariff review, cost-of-service and rate design. Since June 2001, I have been in the Engineering Analysis Section of the Energy Department, which was created by combining the Gas and Electric Departments. I became the Supervisor of the Engineering Analysis Section, Energy Department, Utility Operations Division in November 2005.

I am a Registered Professional Engineer in the State of Missouri. My registration number is E-26953.

List of Cases in which prepared testimony was presented by:
DANIEL I. BECK

Company Name	Case No.
Union Electric Company	EO-87-175
The Empire District Electric Company	EO-91-74
Missouri Public Service	ER-93-37
St. Joseph Power & Light Company	ER-93-41
The Empire District Electric Company	ER-94-174
Union Electric Company	EM-96-149
Laclede Gas Company	GR-96-193
Missouri Gas Energy	GR-96-285
Kansas City Power & Light Company	ET-97-113
Associated Natural Gas Company	GR-97-272
Union Electric Company	GR-97-393
Missouri Gas Energy	GR-98-140
Missouri Gas Energy	GT-98-237
Ozark Natural Gas Company, Inc.	GA-98-227
Laclede Gas Company	GR-98-374
St. Joseph Power & Light Company	GR-99-246
Laclede Gas Company	GR-99-315
Utilicorp United Inc. & St. Joseph Light & Power Co.	EM-2000-292
Union Electric Company d/b/a AmerenUE	GR-2000-512
Missouri Gas Energy	GR-2001-292
Laclede Gas Company	GR-2001-629
Union Electric Company d/b/a AmerenUE	GT-2002-70
Laclede Gas Company	GR-2001-629
Laclede Gas Company	GR-2002-356
Union Electric Company d/b/a AmerenUE	GR-2003-0517
Missouri Gas Energy	GR-2004-0209
Atmos Energy Corporation	GR-2006-0387
Missouri Gas Energy	GR-2006-0422
Union Electric Company d/b/a AmerenUE	GR-2007-0003
The Empire District Electric Company	EO-2007-0029/EE-2007-0030
Laclede Gas Company	GR-2007-0208
The Empire District Electric Company	EO-2008-0043
Missouri Gas Utility, Inc.	GR-2008-0060

Leon Bender's Credentials

I received a Bachelor of Science degree in Mechanical Engineering in August 1978 from Texas Tech University. I became employed by Southwestern Public Service Company (SPS) as a power generation plant design engineer in September 1978. While employed by SPS, I was lead engineer on many projects involving design and construction of new power generating stations and the upgrading of their older plants. In 1983, I became a registered Professional Engineer in the state of Texas. In 1986, I transferred to SPS's newly formed subsidiary company, Utility Engineering Corporation, and was responsible for various projects at various other clients' power generation plants. In June 1990, I accepted employment as a systems engineer with Entergy Operations, Inc. at the nuclear powered generating station, Arkansas Nuclear One. In December 1995, I joined the Missouri Public Service Commission (Commission). While employed by the Commission I have been responsible for determining variable fuel and purchased power cost using the production cost fuel model in numerous cases.

List of Previously Filed Testimony for Leon C. Bender

Case Number	Company Name
1. ER-2007-0291	Kansas City Power & Light Company
2. ER-2007-0002	Union Electric Company d/b/a AmerenUE
3. ER-2007-0004	Aquila, Inc.
4. ER-2007-0002	Union Electric Company d/b/a AmerenUE
5. ER-2006-0314	Kansas City Power & Light Company
6. EA-2006-0309	Aquila, Inc.
7. ER-2005-0436	Aquila, Inc.
8. ER-2004-0570	The Empire District Electric Company
9. ER-2004-0034	Aquila, Inc.
10. EC-2002-0001	Union Electric Company d/b/a AmerenUE
11. ER-2001-0299	The Empire District Electric Company
12. EM-1997-0515	Kansas City Power & Light Company
13. ER-1997-0394	UtiliCorp United, Inc.
14. EC-1997-0362	UtiliCorp United, Inc.

DANA EAVES

CAREER EXPERIENCE

Missouri Public Service Commission, Jefferson City, Missouri

Utility Regulatory Auditor III April 23, 2003– Present

Utility Regulatory Auditor II April, 2002 – April, 2003

Utility Regulatory Auditor I April, 2001 – April, 2002

Perform rate audits and prepare miscellaneous filings as ordered by the Commission. Review all exhibits and testimony on assigned issues from the most recent previous case and the current case. Develop accounting adjustments and issue positions which are supported by workpapers and written testimony. Prepare Staff Recommendation Memorandum for filings that do not require prepared testimony. Act as Lead Auditor for small to middle size rate cases and certificate cases as assigned by management. I have testified under cross-examination as an expert witness for litigated rate cases.

Midwest Block and Brick, Jefferson City, Missouri

Accountant December 2000 – March 2001

CIS/Accounting Assistant July 2000 – December 2000

Practice Management Plus, Inc., Jefferson City, Missouri

Vice President Operations October 1998 – May 2000

Capital City Medical Associates (CCMA), Jefferson City, Missouri

Director of Finance March, 1995-October, 1998

EDUCATION

Bachelor of Science, Business Administration; Emphasis Accounting (1995)

COLUMBIA COLLEGE, JEFFERSON CITY, MO

CASE PROCEEDING PARTICIPATION

DANA E. EAVES

PARTICIPATION		TESTIMONY
COMPANY	CASE NO.	ISSUES
Laclede Gas company	GR-2007-0208	Accounting Schedules Reconcilation
Empire District Electric Company	ER-2006-0315	Direct - Jurisdictional Allocations Factors, Revenue, Uncollectible Expense, Pensions, Prepaid Pension Asset, Other Post-Employment Benefits Rebuttal - Updated: Pension Expense, Updated Prepaid Pension Asset, OPEB's Tracker, Minimum Pension Liability
Missouri Gas Energy (Gas)	GR-2004-0209	Direct – Cash Working Capital, Payroll, Payroll Taxes, Incentive Compensation, Bonuses, Materials and Supplies, Customer Deposits and Interest, Customer Advances and Employee Benefits Surrebuttal – Incentive Compensation
Aquila, Inc. d/b/a Aquila Networks-MPS & L&P (Natural Gas)	GR-2004-0072	Direct - Payroll Expense, Employee Benefits, Payroll Taxes Rebuttal – Payroll Expense, Incentive Compensation, Employer Health, Dental and Vision Expense
Aquila, Inc. d/b/a Aquila Networks-MPS (Electric)	ER-2004-0034	Direct - Payroll Expense, Employee Benefits, Payroll Taxes Rebuttal – Payroll Expense, Incentive Compensation, Employer Health, Dental and Vision Expense
Aquila, Inc. d/b/a Aquila Networks-L&P (Electric & Steam)	HR-2004-0024	Direct - Payroll Expense, Employee Benefits, Payroll Taxes
Osage Water Company	ST-2003-0562 WT-2003-0563	Direct - Plant Adjustment, Operating & Maintenance Expense Adjustments
Empire District Electric Company, The	ER-2002-0424	Direct - Cash Working Capital, Property Tax, Tree Trimming, Injuries and Damages, Outside Services, Misc. Adjustments

PARTICIPATION		TESTIMONY
COMPANY	CASE NO.	ISSUES
Citizens Electric Corporation	ER-2002-0297	Direct - Depreciation Expense, Accumulated Depreciation, Customer Deposits, Material & Supplies, Prepayments, Property Tax, Plant in Service, Customer Advances in Aid of Construction
UtiliCorp United Inc, d/b/a Missouri Public Service	ER-2001-672	Direct - Advertising, Customer Advances, Customer Deposits, Customer Deposit Interest Expense, Dues and Donations, Material and Supply, Prepayments, PSC Assessment, Rate Case Expense

PROCEEDING PARTICIPATION

DANA E. EAVES

PARTICIPATION – No testimony filed or NON-Case (Informal) proceeding		
COMPANY	**CASE or Tracking No.**	**ISSUES**
W.P.C. Sewer Company	QS-2007-0005	Rate Case Lead Auditor
West 16th Street Sewer Company, Inc.	QS-2007-0004	Rate Case Lead Auditor
Gladlo Water & Sewer Company, Inc.	QS-2007-0001 and QW-2007-0002	Rate Case Lead Auditor Supervised: Kofi Boateng
Taneycomo Highlands, Inc.	QS-2006-0004	Rate Case Lead Auditor
Cass County Telephone Company	TO-2005-0237	Cash Flow Analysis, LEC Invoices, Bank Reconciliations, Expense Analysis
LTA Water Company	WM-2005-0058	Merger Case with Missouri American Main Issue: Plant Valuation Lead Auditor
Noel Water Company, Inc.	QW-2005-0002	Rate Case Lead Auditor Supervised: Kofi Boateng
Suburban Water and Sewer Company, Inc.	QW-2005-0001	Rate Case Lead Auditor Supervised: Kofi Boateng
Osage Water Company	WC-2003-0134	Customer Refund Review
Noel Water Company, Inc.	QW-2003-0022	Rate Case Lead Auditor Supervised: Trisha Miller

PARTICIPATION – No testimony filed or NON-Case (Informal) proceeding		
COMPANY	**CASE or Tracking No.**	**ISSUES**
AquaSource	WR-2003-0001 and SR-2003-0002	Plant in Service, Construction Work in Progress, Payroll, Depreciation Expense
Warren County Water and Sewer Company	WC-2002-155	General
Environmental Utilities, LLC	WA-2002-65	General
Meadows Water Company	WR-2001-966 and SR-2001-967	Expense Items

David W. Elliott

Educational Background and Work Experience:

I am employed by the Missouri Public Service Commission (Commission) as a Utility Engineering Specialist III in the Energy Department of the Utility Operations Division.

I graduated from Iowa State University with a Bachelor of Science degree in Mechanical Engineering in May 1975. I was employed by Iowa-Illinois Gas and Electric Company (IIGE) as an engineer from July 1975 to May 1993. While at IIGE, I worked at Riverside Generating Station, first as an assistant to the maintenance engineer, and then as an engineer responsible for monitoring station performance. In 1982, I transferred to the Mechanical Design Division of the Engineering Department where I was an engineer responsible for various projects at IIGE's power plants. In September 1993, I began my employment with the Commission. While employed by The Commission I have been responsible for conducting engineering construction audits for construction of new generating units and power plant equipment.

List of Previous Testimony Filed of David W. Elliott:

1) ER-94-163, St. Joseph Light & Power Co.
2) HR-94-177, St. Joseph Light & Power Co.
3) ER-94-174, The Empire District Electric Co.
4) ER-95-279, The Empire District Electric Co.
5) EM-96-149, Union Electric Co.
6) ER-99-247, St. Joseph Light & Power Co.
7) EM-2000-369, UtiliCorp United, Inc. and The Empire District Electric Co.
8) ER-2001-299, The Empire District Electric Co.
9) ER-2001-672, UtiliCorp United, Inc.

10) ER-2002-424, The Empire District Electric Co.
11) ER-2004-0034, Aquila, Inc.
12) ER-2004-0570, The Empire District Electric Co.
13) HM-2004-0618, Trigen-Kansas City Energy Corp. and Thermal North America, Inc.
14) ER-2005-0436, Aquila, Inc.
15) HR-2005-0450, Aquila, Inc.
16) ER-2006-0314, Kansas City Power & Light Co.
17) ER-2006-0315, The Empire District Electric Co.
18) ER-2007-0004, Aquila, Inc.
19) ER-2007-0291, Kansas City Power & Light Co.

Construction Audit Activities of David W. Elliott:

1) Construction audit and testimony in Case No. ER-2007-0291 respecting Kansas City Power & Light Unit 1 SCR project at La Cygne Station.
2) Construction audit and testimony in Case No. ER-2006-0314 respecting Kansas City Power & Light Hawthorn Units 5,6,7,8,9; West Gardner Units 1,2,3,4; Osawatomie Unit 1; and the Spearville wind farm.
3) Construction audit and testimony in Case No. ER-2004-0570 respecting Empire Energy Center Units 3 & 4.
4) Construction audit and testimony in Case No. ER-2001-0299 respecting Empire State Line Combined Cycle Unit.
5) Preliminary construction audit review respecting AmerenUE Meramec combustion turbine, in May, 2000.

Manisha Lakhanpal

Present Position:

I joined the Missouri Public Service Commission in August 2007 as a Regulatory Economist II in the Economic Analysis Section of the Energy Department, Operations Division.

Educational Background:

In December 2005, I graduated with a Masters of Science in Applied Economics, specializing in Electricity, Natural Gas and Telecommunication, from Illinois State University, Normal, Illinois. I have a Post Graduate Diploma in Business Management from Chetana's Institute of Management and Research, Mumbai, and an undergraduate degree in Political Science and History from University of Delhi, New Delhi, India.

Work Experience:

I first joined Missouri Public Service Commission as an intern in 2006 (May 2006-August 2006). Prior to returning to PSC I was employed by the Indiana Utility Regulatory Commission, Indianapolis, as a Utility Analyst (September 2006- August 2007). During my time in Indiana, I worked on a variety of cases and projects, including a major rate case, wholesale power cost trackers for municipal utilities, environmental cost recovery cases, a certificate of need for the first wind power project in Indiana, as well as a related case involving the purchase of output from the facility, and annual report to the legislature on the state of the industry in Indiana.

In the summer of 2005 (May 2005-July 2005), I worked as an Intern at CommonWealth Edison, Chicago, on projects related to deregulation of electric markets in Illinois.

In India I have worked as an Operations Executive for an insurance company (June 2001- December 2003).

Case Proceeding Participation:

COMPANY	CASE NO.	FILING TYPE/ISSUES
Missouri Gas Utility	GR-2008-0093	Provided Weather Normal Variables for weather normalization

SHAWN E. LANGE

PRESENT POSITION:

I am a Utility Engineering Specialist II in the Engineering Analysis Section, Energy Department, Utility Operations Division.

EDUCATIONAL BACKGROUND AND WORK EXPERIENCE:

In December 2002, I received a Bachelor of Science Degree in Mechanical Engineering from the University of Missouri, at Rolla. Since then, I have pursued dual Masters Degrees in Mechanical Engineering at the University of Missouri, at Columbia and Business Administration at William Woods University. I joined the Commission Staff in January 2005. I am a registered Engineer-in-Training in the State of Missouri.

Direct Testimony

ER-2005-0436	(Aquila Inc.)
ER-2006-0315	(Empire District Electric Company)
ER-2006-0314	(Kansas City Power & Light Company)
ER-2007-0002	(Union Electric Company d/b/a AmerenUE)
ER-2007-0004	(Aquila Inc.)
ER-2007-0291	(Kansas City Power & Light Company)

Rebuttal Testimony

ER-2005-0436	(Aquila Inc.)
ER-2006-0315	(Empire District Electric Company)
ER-2007-0291	(Kansas City Power & Light Company)

Surrebuttal Testimony

ER-2005-0436	(Aquila Inc.)
ER-2006-0314	(Kansas City Power & Light Company)

Erin Maloney

Education

Bachelor of Science Mechanical Engineering
University of Las Vegas Nevada, May 1992

Professional Experience

Missouri Public Service Commission, Jefferson City, MO
January 2005 – Present
Utility Engineering Specialist II

Electronic Data Systems, Kansas City, Missouri
August 1995 – November 2002
System Engineer

Previous Testimony Before the Commission

Case Number	Type of Testimony	Issues
ER-2005-0436	Direct	Reliability
ER-2006-0315	Direct	System Losses and Jurisdictional Demand and Energy Allocation
ER-2006-0314	Direct, Rebuttal, Surrebuttal, True-up Direct	System Losses and Jurisdictional Demand and Energy Allocation
ER-2007-0002	Direct	System Losses and Jurisdictional Energy Allocation
ER-2007-0004	Direct	System Losses and Jurisdictional Energy Allocation

Education and Work Experience Background for
Lena M. Mantle, P.E.
Energy Department Manager
Utility Operations Division

I received a Bachelor of Science Degree in Industrial Engineering from the University of Missouri, at Columbia, in May 1983. I joined the Research and Planning Department of the Missouri Public Service Commission in August 1983. I became the Supervisor of the Engineering Analysis Section of the Energy Department in August, 2001. In July 2005, I was named the Manager of the Energy Department. I am a registered Professional Engineer in the State of Missouri.

In my work at the Commission from May 1983 through August 2001 I worked in many areas of electric utility regulation. Initially I worked on electric utility class cost-of-service analysis. As a member of the Research and Planning Department, I participated in the development of a leading edge methodology for weather normalizing hourly class energy for rate design cases. I applied this methodology to weather normalize energy in numerous rate increase cases. I was actively involved in the writing of the Commission's Chapter 22, Electric Resource Planning rules in the early 1990's and have been a part of the review of every electric resource plan submitted or filed.

My responsibilities as the Supervisor of the Engineering Analysis section considerably broadened my work scope. This section of the Commission Staff is responsible for a wide variety of engineering analysis including electric utility fuel and purchased power expense estimation for rate cases, generation plant construction audits, review of territorial agreements and resolution of customer complaints. As the Manager of the Energy Department I oversee the activities of the Engineering Analysis section, the activities of the electric and natural gas utility tariff filings, the Commission's natural gas safety staff, and the class cost-of-service and rate design for natural gas and electric utilities.

In my work at the Commission I have participated in the development or revision of the following Commission rules:

4 CSR 240-3.130	Filing Requirements and Schedule of Fees for Applications for Approval of Electric Service Territorial Agreements and Petitions for Designation of Electric Service Areas
4 CSR 240-3.135	Filing Requirements and Schedule of Fees Applicable to Applications for Post-Annexation Assignment of Exclusive Service Territories and Determination of Compensation
4 CSR 240-3.161	Electric Utility Fuel and Purchased Power Cost Recovery Mechanisms Filing and Submission Requirements
4 CSR 240-3.162	Electric Utility Environmental Cost Recovery Mechanisms Filing and Submission Requirements
4 CSR 240-3.190	Reporting Requirements for Electric Utilities and Rural Electric Cooperatives
4 CSR 240-14	Utility Promotional Practices
4 CSR 240-18	Safety Standards
4 CSR 240-20.015	Affiliate Transactions
4 CSR 240-20.090	Electric Utility Fuel and Purchased Power Cost Recovery Mechanisms
4 CSR 240-20.091	Electric Utility Environmental Cost Recovery Mechanisms
4 CSR 240-22	Electric Utility Resource Planning

I have testified before the Commission in the following cases:

CASE NUMBER	TYPE OF FILING	ISSUE
ER-84-105	Direct	Demand-Side Update
ER-85-128, et. al	Direct	Demand-Side Update
EO-90-101	Direct, Rebuttal & Surrebuttal	Weather Normalization of Sales; Normalization of Net System
ER-90-138	Direct	Normalization of Net System

CASE NUMBER	TYPE OF FILING	ISSUE
EO-90-251	Rebuttal	Promotional Practice Variance
EO-91-74, et. al.	Direct	Weather Normalization of Class Sales; Normalization of Net System
ER-93-37	Direct	Weather Normalization of Class Sales; Normalization of Net System
ER-94-163	Direct	Normalization of Net System
ER-94-174	Direct	Weather Normalization of Class Sales; Normalization of Net System
EO-94-199	Direct	Normalization of Net System
ET-95-209	Rebuttal & Surrebuttal	New Construction Pilot Program
ER-95-279	Direct	Normalization of Net System
ER-97-81	Direct	Weather Normalization of Class Sales; Normalization of Net System; TES Tariff
EO-97-144	Direct	Weather Normalization of Class Sales; Normalization of Net System;
ER-97-394, et. al.	Direct, Rebuttal & Surrebuttal	Weather Normalization of Class Sales; Normalization of Net System; Energy Audit Tariff
EM-97-575	Direct	Normalization of Net System
EM-2000-292	Direct	Normalization of Net System; Load Research;
ER-2001-299	Direct	Weather Normalization of Class Sales; Normalization of Net System;
EM-2000-369	Direct	Load Research
ER-2001-672	Direct & Rebuttal	Weather Normalization of Class Sales; Normalization of Net System;
ER-2002-1	Direct & Rebuttal	Weather Normalization of Class Sales; Normalization of Net System;

CASE NUMBER	TYPE OF FILING	ISSUE
ER-2002-424	Direct	Derivation of Normal Weather
EF-2003-465	Rebuttal	Resource Planning
ER-2004-0570	Direct	Reliability Indices
ER-2004-0570	Rebuttal & Surrebuttal	Energy Efficiency Programs and Wind Research Program
EO-2005-0263	Spontaneous	DSM Programs and Integrated Resource Planning
EO-2005-0329	Spontaneous	DSM Programs and Integrated Resource Planning
ER-2005-0436	Direct	Resource Planning
ER-2005-0436	Rebuttal	Low-Income Weatherization and Energy Efficiency Programs
ER-2005-0436	Surrebuttal	Low-Income Weatherization and Energy Efficiency Programs; Resource Planning
EA-2006-0309	Rebuttal & Surrebuttal	Resource Planning
EA-2006-0314	Rebuttal	Jurisdictional Allocation Factor
ER-2006-0315	Supplemental Direct	Energy Forecast
ER-2006-0315	Rebuttal	DSM and Low-Income Programs
ER-2007-0002	Direct	DSM Cost Recovery
GR-2007-0003	Direct	DSM Cost Recovery
ER-2007-0004	Direct	Resource Planning

Contributed to Staff Direct Testimony Report

ER-2007-0291 DSM Cost recovery

PAULA MAPEKA

Present Position:

I am currently employed as a Utility Regulatory Auditor II in the Auditing Department, Utility Services Division.

Education Background and Work Experience:

I graduated with a Masters degree in Business Administration from Lincoln University, Jefferson City, Missouri in August 2005. I attained a Bachelor of Science degree in Accounting from Lincoln University in May 2004. Prior to employment with the Commission, I was employed by the Department of Health and Senior Services. I joined the Commission as a Utility Regulatory Auditor I in March 2006.

List of Previously Filed Testimony:

Direct Testimony

GR-2007-0208	Laclede Gas Company
GR-2006-0422	Missouri Gas Energy
ER-2006-0315	Empire District Electric

Rebuttal Testimony

GR-2006-0422	Missouri Gas Energy

Surrebuttal Testimony

GR-2006-0422	Missouri Gas Energy

CASE PARTICIPATION
OF
PAULA MAPEKA

Schedule 1				
Date Filed	**Issue**	**Case Number**	**Exhibit**	**Case Name**
05/24/2007	Accounting Schedules, Rate Base, Plant in Service, Adjustments to Plant in Service, Depreciation Reserve, Cash Working Capital, Interest on IFP & EWP, Depreciation Expense, Cost of Removal, Advertising, Postage Expense, Property Taxes, MO Franchise Taxes, Postage Expenses, Regulatory Expenses, Outside Services	GR20070208	Direct	Laclede Gas Company
06/23/2006	Postage Expenses, Property and Liability Insurance, Injuries and Damages & Worker's Compensation, Customer Deposits, PSC Assessment, Rate Case Expense, Customer Advances, Material &Supplies	ER20060315	Direct	The Empire District Electric Company
10/12/2006	Miscellaneous Expenses, Insurance, Postage, Property Taxes, Regulatory Expenses, Dues & Donations, Accounting Schedules, Promotional Giveaways, Other Ratebase Issues, Advertising, Depreciation Expense, Inquiries & Damages, Interest on Customer Deposits, Case Working Capital, Depreciation Reserve, Plant in Service	GR20060422	Direct	Missouri Gas Energy
11/21/2006	Cash Working Capital, Software Amortization	GR20060422	Rebuttal	Missouri Gas Energy

Amanda C. McMellen
Utility Regulatory Auditor IV

EDUCATION

Bachelors of Science
DeVry Institute of Technology, Kansas City, MO-June 1998

PROFESSIONAL EXPERIENCE

Missouri Public Service Commission
- Utility Regulatory Auditor IV
  - November 2006 – Present
- Utility Regulatory Auditor III
  - June 2002 – November 2006
- Utility Regulatory Auditor II
  - June 2000 – June 2002
- Utility Regulatory Auditor I
  - June 1999 – June 2000

I am a Utility Regulatory Auditor for the Missouri Public Service Commission (Commission). I graduated from the DeVry Institute of Technology in June 1998 with a Bachelor of Science degree in Accounting. Before coming to work at the Commission, I worked as an accounts receivable clerk. I commenced employment with the Commission Staff in June 1999. As a Utility Regulatory Auditor, I am responsible for assisting in the audits and examinations of the books and records of utility companies operating within the state of Missouri.

SUMMARY OF RATE CASE TESTIMONY FILED

Amanda C. McMellen

COMPANY	CASE NO.	ISSUES
Osage Water Company	SR-2000-556	Plant in Service Depreciation Reserve Depreciation Expense Operation & Maintenance Expense
Osage Water Company	WR-2000-557	Plant in Service Depreciation Reserve Depreciation Expense Operation & Maintenance Expense
Empire District Electric Company	ER-2001-299	Plant in Service Depreciation Reserve Depreciation Expense Cash Working Capital Other Working Capital Rate Case Expense PSC Assessment Advertising Dues, Donations & Contributions
UtiliCorp United, Inc./ d/b/a Missouri Public Service	ER-2001-672	Insurance Injuries and Damages Property Taxes Lobbying Outside Services Maintenance SJLP Related Expenses
BPS Telephone Company	TC-2002-1076	Accounting Schedules Separation Factors Plant in Service Depreciation Reserve Revenues Payroll Payroll Related Benefits Other Expenses

SUMMARY OF RATE CASE TESTIMONY FILED

Amanda C. McMellen

COMPANY	CASE NO.	ISSUES
Aquila, Inc. d/b/a Aquila Networks-MPS & Aquila Networks-L&P	ER-2004-0034	Revenue Annualizations Uncollectibles
Fidelity Telephone Company	IR-2004-0272	Revenue Revenue Related Expenses
Aquila, Inc. d/b/a Aquila Networks-MPS & Aquila Networks-L&P	ER-2005-0436	Revenue Annualizations Uncollectibles
Empire District Electric Company	ER-2006-0315	Payroll Payroll Taxes 401(k) Plan Health Care Costs Incentive Compensation Depreciation Expense Amortization Expense Customer Demand Program Deferred State Income Taxes Income Taxes
Aquila, Inc. d/b/a Aquila Networks-MPS & Aquila Networks-L&P	ER-2007-0004	Revenue Annualizations Uncollectibles Maintenance Expenses Turbine Overhaul Maintenance

David Roos
Witness Experience and Credentials

I am a Regulatory Economist III in the Economic Analysis Section, Energy Department, Operations Division of the Missouri Public Service Commission.

I graduated from the University of Notre Dame, Notre Dame, Indiana, with a Bachelor of Science degree in Chemical Engineering in May 1983. I received a Master of Arts degree in Economics from the University of Missouri in December 2005. I have been employed at the Missouri Public Service Commission as a Regulatory Economist III since March 2006. Prior to joining the Public Service Commission, I taught introductory economics and conducted research as a graduate teaching assistant and graduate research assistant at the University of Missouri. Prior to the University of Missouri, I was employed by several private firms where I provided consulting, design, and construction oversight of environmental projects for private and public sector clients.

List of Reports and Testimony Filed before the Commission

Empire District Electric Company	ER-2006-0315
AmerenUE	ER-2007-0002
Aquila	ER-2007-0004
Kansas City Power & Light Company	ER-2007-0291

ROSELLA SCHAD, PE, CPA

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Education

University of Missouri-Columbia
The Gordon E. Crosby, Jr., MBA Program
Emphasis: Finance
Candidate for Master's of Business Administration, May 2008

Columbia College
27-hours Accounting

University of Missouri-Columbia
The Truman School of Public Affairs
Master's of Public Administration, May 2004
Emphasis: Public Management

University of Missouri-Columbia
Bachelor's of Science in Mechanical Engineering, Honors Scholar, May 1978

Professional Experience

3/99 to Present *Engineer*, **Missouri Public Service Commission,** Jefferson City, Missouri

- Perform depreciation reserve studies using statistical analysis techniques, engineering judgment, familiarity of the regulated industries, and knowledge of company specific operations and maintenance resulting in equitable utility rates for the Missouri consumers
- Prepare recommendations and provide written and oral testimony supporting staff regulated utility depreciation rates
- Facilitate engineering "quality of service" inspections and audits
- Review other staff depreciation analyses, including auditing documentation
- Develop a telecommunications industry seminar to address technical issues for legislators, regulators, businesses, educators, and other state agencies

6/78 to 11/80 *Engineer*, **Union Electric, Callaway Nuclear Plant,** Fulton, Missouri

- Evaluated procurement contracts with construction contractors and equipment and material suppliers resulting in substantial savings for the construction project.
- Audited construction projects for adherence to applicable standards and codes
- Surveyed equipment and materials specifications for manufacturing, distribution, and installation requirements and criteria

Certification

Missouri Professional Engineer (P.E.)
Missouri Certified Public Accountant (C.P.A.)

Professional Membership

National/Missouri Society of Professional Engineers
Missouri Society of Certified Public Accountants
Society of Depreciation Professionals

CASE PROCEEDING PARTICIPATION

ROSELLA L. SCHAD, PE, CPA

COMPANY	CASE NO./ FILING	ISSUES
Missouri Gas Utility, Inc.	GR-2008-0060 Direct	Report - Depreciation
Aquila, Inc. d/b/a Aquila Networks-MPS and Aquila Networks-L&P	ER-2007-0004 Direct	Depreciation
Algonquin Water Resources of Missouri, LLC	WR-2006-0425 & SR-2006-0426 (Consolidated) Direct, Rebuttal, Surrebuttal	Depreciation
Kansas City Power & Light Co.	ER-2006-0314 Direct and Surrebuttal	Depreciation
Silverleaf Resorts, Inc. and Algonquin Water Resources of Missouri, LLC	WO-2005-0206 Rebuttal	Depreciation
Laclede Gas Company	GR-99-315 Supplemental Rebuttal	Depreciation, Cost of Removal, and Net Salvage
Laclede Gas Company	GR-99-315 Supplemental Direct	Depreciation, Cost of Removal, and Net Salvage
AQUILA, INC. d/b/a AQUILA NETWORKS-MPS (Electric) and AQUILA NETWORKS – L&P (Electric and Steam)	ER-2004-0034 and HR-2004-0024 (Consolidated) Surrebuttal	Production Plant Retirement Dates; Accumulated Depreciation; Cost of Removal and Depreciation
AQUILA, INC. d/b/a AQUILA NETWORKS-MPS AND AQUILA NETWORKS-L&P	GR-2004-0072 Rebuttal	Depreciation; Accumulated Depreciation; Cost of Removal and Production Plant Retirement Dates
AQUILA, INC. d/b/a AQUILA NETWORKS-MPS (Electric) and AQUILA NETWORKS – L&P (Electric and Steam)	ER-2004-0034 and HR-2004-0024 (Consolidated) Rebuttal	Production Plant Retirement Dates; Accumulated Depreciation Reserve Balances; Cost of Removal and Depreciation

COMPANY	CASE NO./ FILING	ISSUES
AQUILA, INC. d/b/a AQUILA NETWORKS-MPS AND AQUILA NETWORKS-L&P	GR-2004-0072 Direct	Depreciation and Accumulated Depreciation Reserve
AQUILA, INC. d/b/a AQUILA NETWORKS-MPS (Electric) and AQUILA NETWORKS – L&P (Electric and Steam)	ER-2004-0034 and HR-2004-0024 (Consolidated) Direct	Depreciation and Accumulated Depreciation Reserve
Laclede Gas Company	GR-2002-356 Rebuttal	Decommissioning
Laclede Gas Company	GR-2002-356 Direct	Depreciation
Union Electric Company d/b/a AmerenUE	EC-2002-1 Surrebuttal	Depreciation; Steam Production Plant Retirement Dates; Decommissioning Costs; Callaway Interim Additions
Laclede Gas Company	GR-2001-629 Direct	Depreciation
Ozark Telephone Company	TC-2001-402 Direct	Depreciation Rates
Northeast Missouri Rural Telephone Company	TR-2001-344 Direct, Surrebuttal	Depreciation Rates
Oregon Farmers Mutual Telephone Company	TT-2001-328 Rebuttal	Depreciation Rates
KLM Telephone Company	TT-2001-120 Rebuttal	Depreciation Rates
Holway Telephone Company	TT-2001-119 Rebuttal	Depreciation Rates
Peace Valley Telephone Company	TT-2001-118 Rebuttal	Depreciation Rates
Iamo Telephone Company	TT-2001-116 Rebuttal	Depreciation Rates
Osage Water Company	WR-2000-557 Direct	Depreciation
Osage Water Company	SR-2000-556 Direct	Depreciation

MICHAEL E. TAYLOR

- Bachelor of Science degree in Mechanical Engineering, University of Missouri-Rolla, 1972

- Master of Science degree in Engineering Management, University of Missouri-Rolla, 1987

- United States Navy (Submarine Service), 1972 to 1979

- Union Electric Company (AmerenUE), 1979 to 2003
  Experience included Callaway Plant operations, work control, engineering, quality assurance, quality control, instrumentation and controls, fire protection, industrial safety, outage scheduling, daily scheduling and work planning
  Licensed as a Senior Reactor Operator

- Missouri Public Service Commission Staff, 2003 to present
  Utility Engineering Specialist II, Safety/Engineering, Energy Department
  Utility Engineering Specialist III, Engineering Analysis, Energy Department

PREVIOUS TESTIMONY OF MICHAEL E. TAYLOR

Case Number	Company	Type of Filing	Issue
ER-2006-0314	Kansas City Power & Light	Direct	Plant in Service
ER-2006-0314	Kansas City Power & Light	True-Up Direct	Plant in Service
ER-2007-0002	AmerenUE	Direct	Plant in Service
ER-2007-0002	AmerenUE	Supplemental Direct	Plant in Service
ER-2007-0004	Aquila	Rebuttal	Fuel Adjustment Clause
ER-2007-0291	Kansas City Power & Light	Staff Report	Plant in Service

Curt Wells

Present Position:

I am a Regulatory Economist in the Economic Analysis Section, Energy Department, Operations Division of the Missouri Public Service Commission.

Educational Background and Work Experience:

I have a Bachelor's degree in Economics from Duke University, a Master's degree in Economics from The Pennsylvania State University, and a Master's degree in Applied Economics from Southern Methodist University. I have been employed by the Missouri Public Service Commission since February, 2006. Prior to joining the Commission, I completed a career in the U.S. Air Force, which included assignments as a navigator in weather reconnaissance aircraft, and later in the Purchasing/Contracting area as Contract Negotiator and Administrator, Contracting Policy Manager, Installation Purchasing Department Chief, and Contracting Program Manager.

CURT WELLS

TESTIMONY FILED BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

Case Number	Company	Issue
ER-2006-0315	Empire District Electric	Revenue
ER-2006-0314	Kansas City Power & Light Company	Calculation of Normal Weather, Revenue
GR-2006-0387	ATMOS Energy Corporation	Calculation of Normal Weather
GR-2006-0422	Missouri Gas Energy	Calculation of Normal Weather
ER-2007-0002	Union Electric d/b/a AmerenUE	Calculation of Normal Weather, Large Customer Annualization
GR-2007-0003	Union Electric d/b/a AmerenUE	Calculation of Normal Weather
ER-2007-0004	Aquila, Inc	Calculation of Normal Weather, Revenue
GR-2007-0208	Laclede Gas Company	Calculation of Normal Weather
ER-2007-0291	Kansas City Power & Light Co.	Calculation of Normal Weather, Large Power Revenue

AN ANALYSIS OF THE COST OF CAPITAL

FOR

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2008-0093

SCHEDULES

BY

MATTHEW J. BARNES

UTILITY SERVICES DIVISION

MISSOURI PUBLIC SERVICE COMMISSION

FEBRUARY 2008

The Empire District Electric Company
Case No. ER-2008-0093

List of Schedules

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2-2	Graph of Federal Reserve Discount Rates and Federal Funds Rates Changes
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5-2	Average Yields on Thirty-Year U.S. Treasury Bonds
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21	Weighted Cost of Capital as of December 31, 2007 for The Empire District Electric Company

The Empire District Electric Company
Case No. ER-2008-0093

Federal Reserve Discount Rate Changes

Date	Federal Reserve Discount Rate	Federal Reserve Funds Rate
07/19/82	11.50%	
07/31/82	11.00%	
08/14/82	10.50%	
08/26/82	10.00%	
10/10/82	9.50%	
11/20/82	9.00%	
12/14/82	8.50%	
01/01/83	8.50%	
12/31/83	8.50%	
04/09/84	9.00%	
11/21/84	8.50%	
12/24/84	8.00%	
05/20/85	7.50%	
03/07/86	7.00%	
04/21/86	6.50%	
07/11/86	6.00%	
08/21/86	5.50%	
09/04/87	6.00%	
08/09/88	6.50%	
02/24/89	7.00%	
07/13/90	7.00%	8.00% *
10/29/90	7.00%	7.75%
11/13/90	7.00%	7.50%
12/07/90	7.00%	7.25%
12/18/90	7.00%	7.00%
12/19/90	6.50%	7.00%
01/09/91	6.50%	6.75%
02/01/91	6.00%	6.25%
03/08/91	6.00%	6.00%
04/30/91	5.50%	5.75%
08/06/91	5.50%	5.50%
09/13/91	5.00%	5.25%
10/31/91	5.00%	5.00%
11/06/91	4.50%	4.75%
12/06/91	4.50%	4.50%
12/20/91	3.50%	4.00%
04/09/92	3.50%	3.75%
07/02/92	3.00%	3.25%
09/04/92	3.00%	3.00%
01/01/93	3.00%	3.00%
12/31/93	3.00%	3.00%
02/04/94	3.00%	3.25%
03/22/94	3.00%	3.50%
04/18/94	3.00%	3.75%
05/17/94	3.50%	4.25%
08/16/94	4.00%	4.75%
11/15/94	4.75%	5.50%
02/01/95	5.25%	6.00%
07/06/95	5.25%	5.75%
12/19/95	5.25%	5.50%
01/31/96	5.00%	5.25%

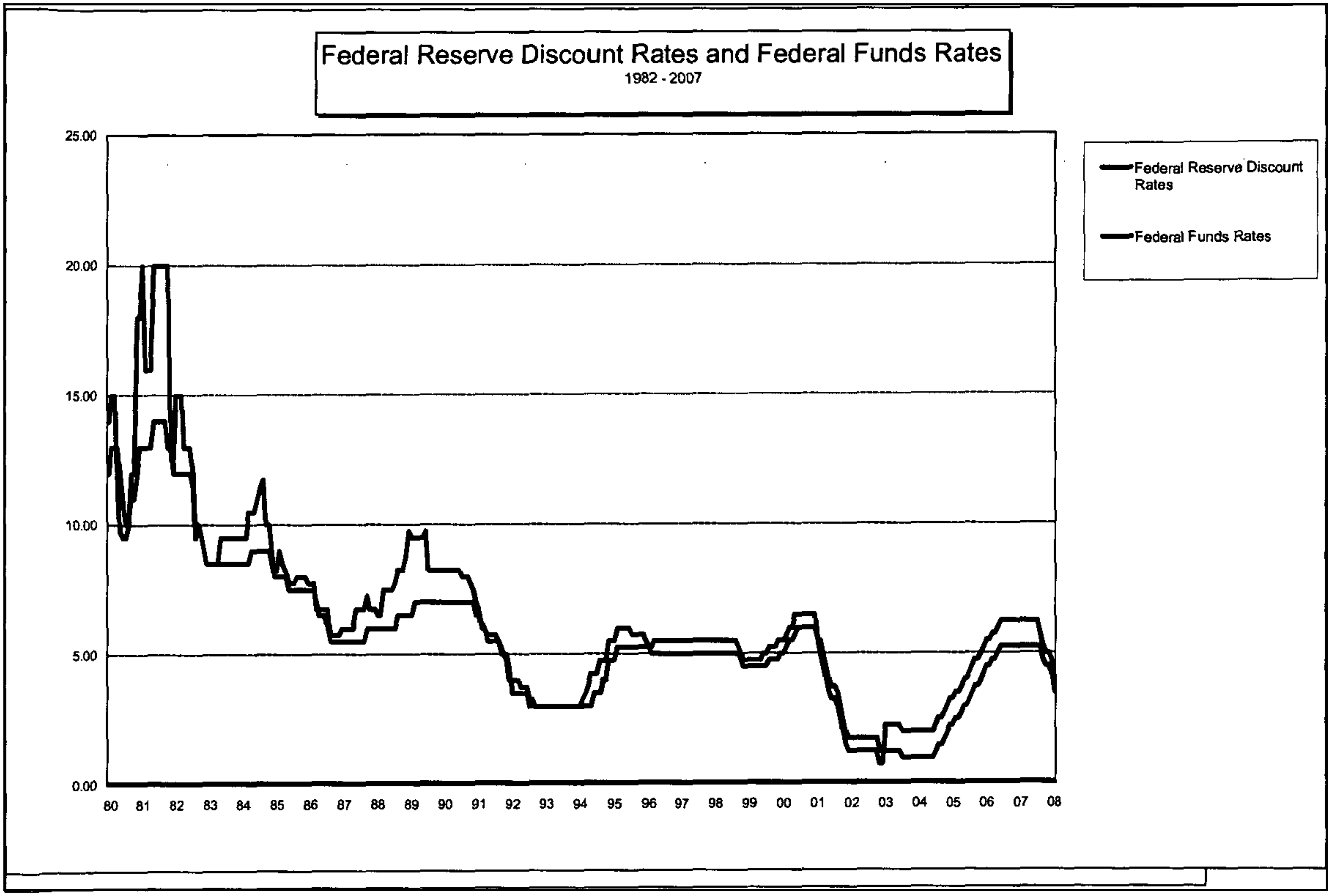
Date	Federal Reserve Discount Rate	Federal Reserve Funds Rate
03/25/97	5.00%	5.50%
12/12/97	5.00%	5.50%
01/09/98	5.00%	5.50%
03/06/98	5.00%	5.50%
09/29/98	5.00%	5.25%
10/15/98	4.75%	5.00%
11/17/98	4.50%	4.75%
06/30/99	4.50%	5.00%
08/24/99	4.75%	5.25%
11/16/99	5.00%	5.50%
02/02/00	5.25%	5.75%
03/21/00	5.50%	6.00%
05/19/00	6.00%	6.50%
01/03/01	5.75%	6.00%
01/04/01	5.50%	6.00%
01/31/01	5.00%	5.50%
03/20/01	4.50%	5.00%
04/18/01	4.00%	4.50%
05/15/01	3.50%	4.00%
06/27/01	3.25%	3.75%
08/21/01	3.00%	3.50%
09/17/01	2.50%	3.00%
10/02/01	2.00%	2.50%
11/06/01	1.50%	2.00%
12/11/01	1.25%	1.75%
11/06/02	0.75%	1.25%
01/09/03	2.25%**	1.25%
06/25/03	2.00%	1.00%
06/30/04	2.25%	1.25%
08/10/04	2.50%	1.50%
09/21/04	2.75%	1.75%
11/10/04	3.00%	2.00%
12/14/04	3.25%	2.25%
02/02/05	3.50%	2.50%
03/22/05	3.75%	2.75%
05/03/05	4.00%	3.00%
06/30/05	4.25%	3.25%
08/09/05	4.50%	3.50%
09/20/05	4.75%	3.75%
11/01/05	5.00%	4.00%
12/13/05	5.25%	4.25%
01/31/06	5.50%	4.50%
03/28/06	5.75%	4.75%
05/10/06	6.00%	5.00%
06/29/06	6.25%	5.25%
08/17/07	5.75%	5.25%
09/18/07	5.25%	4.75%
10/31/07	5.00%	4.50%
11/11/07	4.75%	4.25%
01/22/08	4.00%	3.50%
01/30/08	3.50%	3.00%

* Staff began tracking the Federal Funds Rate.
**Revised discount window program begins. Reflects rate on primary credit. This revised discount window policy results in incomparability of the discount rates after January 9, 2003 to discount rates before January 9, 2003.

Source:
Federal Reserve Discount rate http://www.newyorkfed.org/markets/statistics/dlyrates/fedrate.html
Federal Reserve Funds rate http://www.newyorkfed.org/markets/statistics/dlyrates/fedrate.html

Note: Interest rates as of December 31 for each year are underlined.

The Empire District Electric Company
Case No. ER-2008-0093



SCHEDULE 2-2

The Empire District Electric Company
Case No. ER-2008-0093

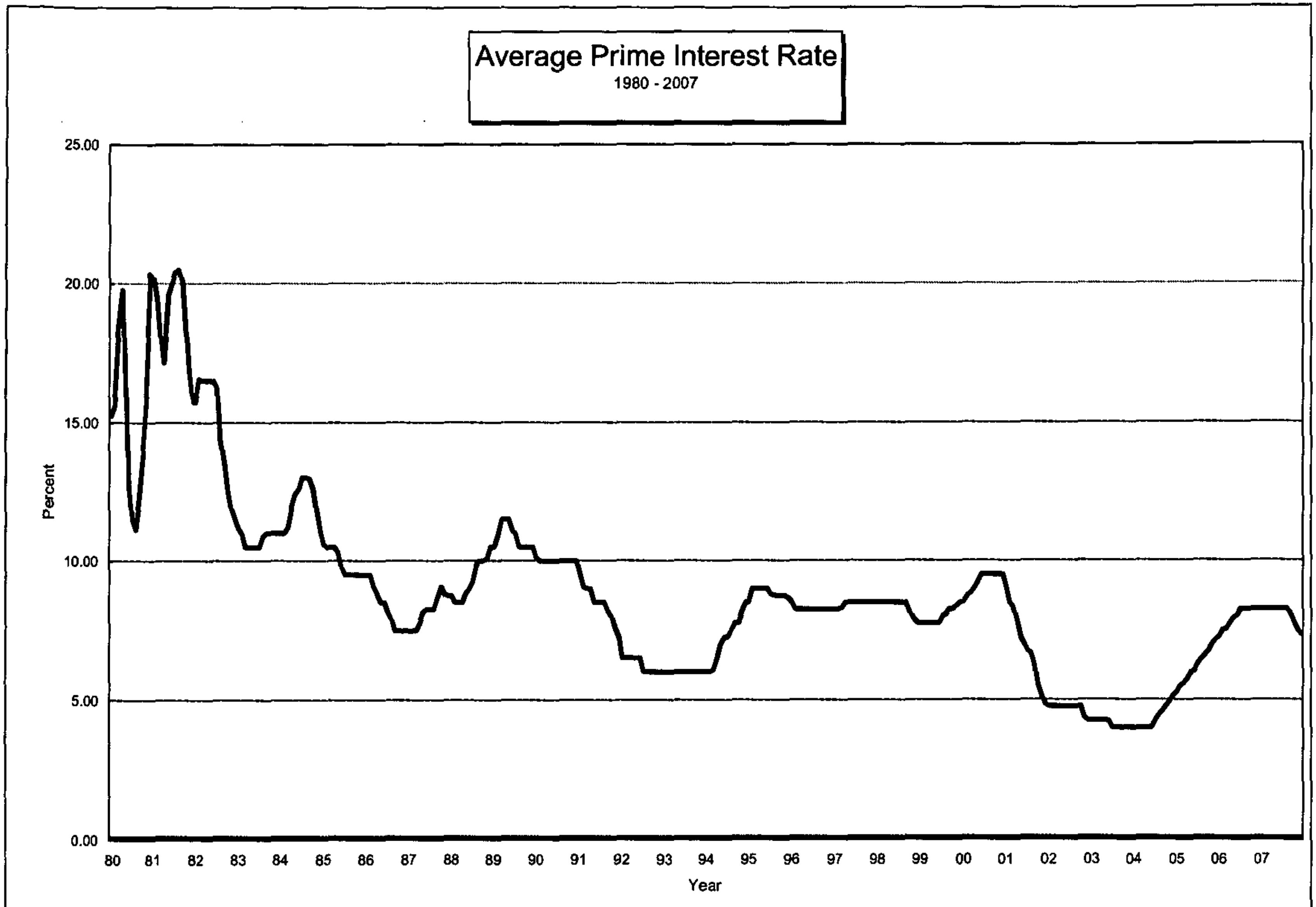
Average Prime Interest Rates

Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)
Jan 1980	15.25	Jan 1984	11.00	Jan 1988	8.75	Jan 1992	6.50	Jan 1996	8.50	Jan 2000	8.50	Jan 2004	4.00
Feb	15.63	Feb	11.00	Feb	8.51	Feb	6.50	Feb	8.25	Feb	8.73	Feb	4.00
Mar	18.31	Mar	11.21	Mar	8.50	Mar	6.50	Mar	8.25	Mar	8.83	Mar	4.00
Apr	19.77	Apr	11.93	Apr	8.50	Apr	6.50	Apr	8.25	Apr	9.00	Apr	4.00
May	16.57	May	12.39	May	8.84	May	6.50	May	8.25	May	9.24	May	4.00
Jun	12.63	Jun	12.60	Jun	9.00	Jun	6.50	Jun	8.25	Jun	9.50	Jun	4.00
Jul	11.48	Jul	13.00	Jul	9.29	Jul	6.02	Jul	8.25	Jul	9.50	Jul	4.25
Aug	11.12	Aug	13.00	Aug	9.84	Aug	6.00	Aug	8.25	Aug	9.50	Aug	4.43
Sep	12.23	Sep	12.97	Sep	10.00	Sep	6.00	Sep	8.25	Sep	9.50	Sep	4.58
Oct	13.79	Oct	12.58	Oct	10.00	Oct	6.00	Oct	8.25	Oct	9.50	Oct	4.75
Nov	16.06	Nov	11.77	Nov	10.05	Nov	6.00	Nov	8.25	Nov	9.50	Nov	4.93
Dec	20.35	Dec	11.06	Dec	10.50	Dec	6.00	Dec	8.25	Dec	9.50	Dec	5.15
Jan 1981	20.16	Jan 1985	10.61	Jan 1989	10.50	Jan 1993	6.00	Jan 1997	8.26	Jan 2001	9.05	Jan 2005	5.25
Feb	19.43	Feb	10.50	Feb	10.93	Feb	6.00	Feb	8.25	Feb	8.50	Feb	5.49
Mar	18.05	Mar	10.50	Mar	11.50	Mar	6.00	Mar	8.30	Mar	8.32	Mar	5.58
Apr	17.15	Apr	10.50	Apr	11.50	Apr	6.00	Apr	8.50	Apr	7.80	Apr	5.75
May	19.61	May	10.31	May	11.50	May	6.00	May	8.50	May	7.24	May	5.98
Jun	20.03	Jun	9.78	Jun	11.07	Jun	6.00	Jun	8.50	Jun	6.98	Jun	6.01
Jul	20.39	Jul	9.50	Jul	10.98	Jul	6.00	Jul	8.50	Jul	6.75	Jul	6.25
Aug	20.50	Aug	9.50	Aug	10.50	Aug	6.00	Aug	8.50	Aug	6.67	Aug	6.44
Sep	20.08	Sep	9.50	Sep	10.50	Sep	6.00	Sep	8.50	Sep	6.28	Sep	6.59
Oct	18.45	Oct	9.50	Oct	10.50	Oct	6.00	Oct	8.50	Oct	5.53	Oct	6.75
Nov	16.84	Nov	9.50	Nov	10.50	Nov	6.00	Nov	8.50	Nov	5.10	Nov	7.00
Dec	15.75	Dec	9.50	Dec	10.50	Dec	6.00	Dec	8.50	Dec	4.84	Dec	7.15
Jan 1982	15.75	Jan 1986	9.50	Jan 1990	10.11	Jan 1994	6.00	Jan 1998	8.50	Jan 2002	4.75	Jan 2006	7.26
Feb	16.56	Feb	9.50	Feb	10.00	Feb	6.00	Feb	8.50	Feb	4.75	Feb	7.50
Mar	16.50	Mar	9.10	Mar	10.00	Mar	6.06	Mar	8.50	Mar	4.75	Mar	7.53
Apr	16.50	Apr	8.83	Apr	10.00	Apr	6.45	Apr	8.50	Apr	4.75	Apr	7.75
May	16.50	May	8.50	May	10.00	May	6.99	May	8.50	May	4.75	May	7.93
Jun	16.50	Jun	8.50	Jun	10.00	Jun	7.25	Jun	8.50	Jun	4.75	June	8.02
Jul	16.26	Jul	8.16	Jul	10.00	Jul	7.25	Jul	8.50	Jul	4.75	July	8.25
Aug	14.39	Aug	7.90	Aug	10.00	Aug	7.51	Aug	8.50	Aug	4.75	Aug	8.25
Sep	13.50	Sep	7.50	Sep	10.00	Sep	7.75	Sep	8.49	Sep	4.75	Sep	8.25
Oct	12.52	Oct	7.50	Oct	10.00	Oct	7.75	Oct	8.12	Oct	4.75	Oct	8.25
Nov	11.85	Nov	7.50	Nov	10.00	Nov	8.15	Nov	7.89	Nov	4.35	Nov	8.25
Dec	11.50	Dec	7.50	Dec	10.00	Dec	8.50	Dec	7.75	Dec	4.25	Dec	8.25
Jan 1983	11.16	Jan 1987	7.50	Jan 1991	9.52	Jan 1995	8.50	Jan 1999	7.75	Jan 2003	4.25	Jan 2007	8.25
Feb	10.98	Feb	7.50	Feb	9.05	Feb	9.00	Feb	7.75	Feb	4.25	Feb	8.25
Mar	10.50	Mar	7.50	Mar	9.00	Mar	9.00	Mar	7.75	Mar	4.25	Mar	8.25
Apr	10.50	Apr	7.75	Apr	9.00	Apr	9.00	Apr	7.75	Apr	4.25	Apr	8.25
May	10.50	May	8.14	May	8.50	May	9.00	May	7.75	May	4.25	May	8.25
Jun	10.50	Jun	8.25	Jun	8.50	Jun	9.00	Jun	7.75	Jun	4.22	June	8.25
Jul	10.50	Jul	8.25	Jul	8.50	Jul	8.80	Jul	8.00	Jul	4.00	July	8.25
Aug	10.89	Aug	8.25	Aug	8.50	Aug	8.75	Aug	8.06	Aug	4.00	Aug	8.25
Sep	11.00	Sep	8.70	Sep	8.20	Sep	8.75	Sep	8.25	Sep	4.00	Sep	8.03
Oct	11.00	Oct	9.07	Oct	8.00	Oct	8.75	Oct	8.25	Oct	4.00	Oct	7.74
Nov	11.00	Nov	8.78	Nov	7.58	Nov	8.75	Nov	8.37	Nov	4.00	Nov	7.50
Dec	11.00	Dec	8.75	Dec	7.21	Dec	8.65	Dec	8.50	Dec	4.00	Dec	7.33

Source:
http://research.stlouisfed.org/fred2/data/MPRIME.txt

SCHEDULE 3-1

The Empire District Electric Company
Case No. ER-2008-0093



SCHEDULE 3-2

The Empire District Electric Company
Case No. ER-2008-0093

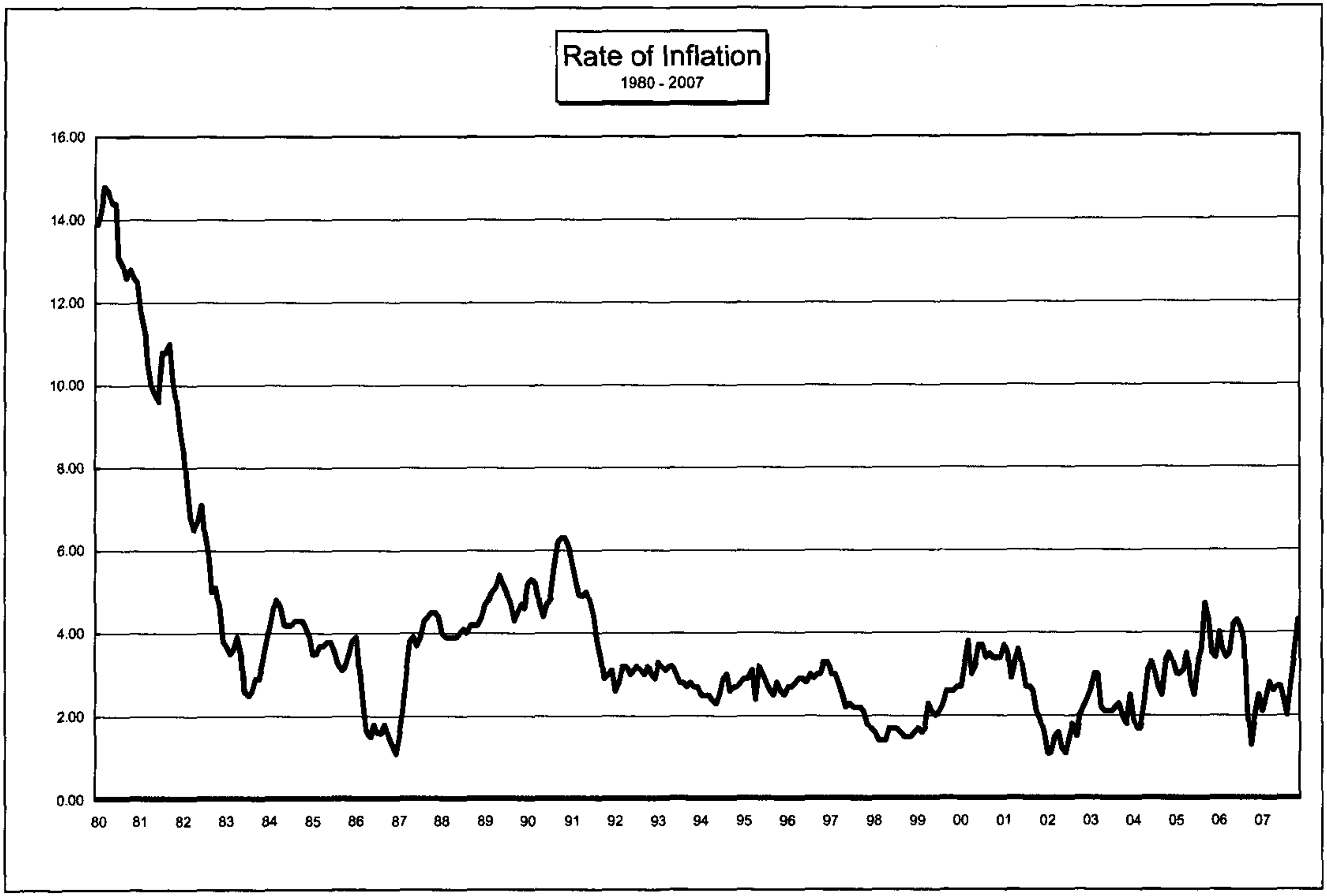
Rate of Inflation

Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)
Jan 1980	13.90	Jan 1984	4.20	Jan 1988	4.00	Jan 1992	2.60	Jan 1996	2.70	Jan 2000	2.70	Jan 2004	1.90
Feb	14.20	Feb	4.60	Feb	3.90	Feb	2.80	Feb	2.70	Feb	3.20	Feb	1.70
Mar	14.80	Mar	4.80	Mar	3.90	Mar	3.20	Mar	2.80	Mar	3.70	Mar	1.70
Apr	14.70	Apr	4.60	Apr	3.90	Apr	3.20	Apr	2.90	Apr	3.00	Apr	2.30
May	14.40	May	4.20	May	3.90	May	3.00	May	2.90	May	3.20	May	3.10
Jun	14.40	Jun	4.20	Jun	4.00	Jun	3.10	Jun	2.80	Jun	3.70	Jun	3.30
Jul	13.10	Jul	4.20	Jul	4.10	Jul	3.20	Jul	3.00	Jul	3.70	Jul	3.00
Aug	12.90	Aug	4.30	Aug	4.00	Aug	3.10	Aug	2.90	Aug	3.40	Aug	2.70
Sep	12.60	Sep	4.30	Sep	4.20	Sep	3.00	Sep	3.00	Sep	3.50	Sep	2.50
Oct	12.80	Oct	4.30	Oct	4.20	Oct	3.20	Oct	3.00	Oct	3.40	Oct	3.30
Nov	12.60	Nov	4.10	Nov	4.20	Nov	3.00	Nov	3.30	Nov	3.40	Nov	3.50
Dec	12.50	Dec	3.90	Dec	4.40	Dec	2.90	Dec	3.30	Dec	3.40	Dec	3.30
Jan 1981	11.80	Jan 1985	3.50	Jan 1989	4.70	Jan 1993	3.30	Jan 1997	3.00	Jan 2001	3.70	Jan 2005	3.00
Feb	11.40	Feb	3.50	Feb	4.80	Feb	3.20	Feb	3.00	Feb	3.50	Feb	3.00
Mar	10.50	Mar	3.70	Mar	5.00	Mar	3.10	Mar	2.80	Mar	2.90	Mar	3.10
Apr	10.00	Apr	3.70	Apr	5.10	Apr	3.20	Apr	2.50	Apr	3.30	Apr	3.50
May	9.80	May	3.80	May	5.40	May	3.20	May	2.20	May	3.60	May	2.80
Jun	9.60	Jun	3.80	Jun	5.20	Jun	3.00	Jun	2.30	Jun	3.20	Jun	2.50
Jul	10.80	Jul	3.60	Jul	5.00	Jul	2.80	Jul	2.20	Jul	2.70	Jul	3.20
Aug	10.80	Aug	3.30	Aug	4.70	Aug	2.80	Aug	2.20	Aug	2.70	Aug	3.60
Sep	11.00	Sep	3.10	Sep	4.30	Sep	2.70	Sep	2.20	Sep	2.60	Sep	4.70
Oct	10.10	Oct	3.20	Oct	4.50	Oct	2.80	Oct	2.10	Oct	2.10	Oct	4.30
Nov	9.60	Nov	3.50	Nov	4.70	Nov	2.70	Nov	1.80	Nov	1.90	Nov	3.50
Dec	8.90	Dec	3.80	Dec	4.60	Dec	2.70	Dec	1.70	Dec	1.60	Dec	3.40
Jan 1982	8.40	Jan 1986	3.90	Jan 1990	5.20	Jan 1994	2.50	Jan 1998	1.60	Jan 2002	1.10	Jan 2006	4.00
Feb	7.60	Feb	3.10	Feb	5.30	Feb	2.50	Feb	1.40	Feb	1.10	Feb	3.60
Mar	6.80	Mar	2.30	Mar	5.20	Mar	2.50	Mar	1.40	Mar	1.50	Mar	3.40
Apr	6.50	Apr	1.60	Apr	4.70	Apr	2.40	Apr	1.40	Apr	1.60	Apr	3.50
May	6.70	May	1.50	May	4.40	May	2.30	May	1.70	May	1.20	May	4.20
Jun	7.10	Jun	1.80	Jun	4.70	Jun	2.50	Jun	1.70	Jun	1.10	June	4.30
Jul	6.40	Jul	1.60	Jul	4.80	Jul	2.90	Jul	1.70	Jul	1.50	July	4.10
Aug	5.90	Aug	1.60	Aug	5.60	Aug	3.00	Aug	1.60	Aug	1.80	Aug	3.80
Sep	5.00	Sep	1.80	Sep	6.20	Sep	2.60	Sep	1.50	Sep	1.50	Sep	2.10
Oct	5.10	Oct	1.50	Oct	6.30	Oct	2.70	Oct	1.50	Oct	2.00	Oct	1.30
Nov	4.60	Nov	1.30	Nov	6.30	Nov	2.70	Nov	1.50	Nov	2.20	Nov	2.00
Dec	3.80	Dec	1.10	Dec	6.10	Dec	2.80	Dec	1.60	Dec	2.40	Dec	2.50
Jan 1983	3.70	Jan 1987	1.50	Jan 1991	5.70	Jan 1995	2.90	Jan 1999	1.70	Jan 2003	2.60	Jan 2007	2.10
Feb	3.50	Feb	2.10	Feb	5.30	Feb	2.90	Feb	1.60	Feb	3.00	Feb	2.40
Mar	3.60	Mar	3.00	Mar	4.90	Mar	3.10	Mar	1.70	Mar	3.00	Mar	2.80
Apr	3.90	Apr	3.80	Apr	4.90	Apr	2.40	Apr	2.30	Apr	2.20	Apr	2.60
May	3.50	May	3.90	May	5.00	May	3.20	May	2.10	May	2.10	May	2.70
Jun	2.60	Jun	3.70	Jun	4.70	Jun	3.00	Jun	2.00	Jun	2.10	Jun	2.70
Jul	2.50	Jul	3.90	Jul	4.40	Jul	2.80	Jul	2.10	Jul	2.10	Jul	2.40
Aug	2.60	Aug	4.30	Aug	3.80	Aug	2.60	Aug	2.30	Aug	2.20	Aug	2.00
Sep	2.90	Sep	4.40	Sep	3.40	Sep	2.50	Sep	2.60	Sep	2.30	Sep	2.80
Oct	2.90	Oct	4.50	Oct	2.90	Oct	2.80	Oct	2.60	Oct	2.00	Oct	3.50
Nov	3.30	Nov	4.50	Nov	3.00	Nov	2.60	Nov	2.60	Nov	1.80	Nov	4.30
Dec	3.80	Dec	4.40	Dec	3.10	Dec	2.50	Dec	2.70	Dec	1.90		

Source: U.S. Dept of Labor, Bureau of Labor Statistics, Consumer Price Index - All Urban Consumers, Change for 12-Month Period, Bureau of Labor Statistics, http://www.bls.gov/schedule/archives/cpi_nr.htm

SCHEDULE 4-1

The Empire District Electric Company
Case No. ER-2008-0093



SCHEDULE 4-2

SCHEDULE 4-2

The Empire District Electric Company
Case No. ER-2008-0093

Average Yields on Mergent's Public Utility Bonds

Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)
Jan 1980	12.12	Jan 1984	13.40	Jan 1988	10.75	Jan 1992	8.67	Jan 1996	7.20	Jan 2000	8.22	Jan 2004	6.23
Feb	13.48	Feb	13.50	Feb	10.11	Feb	8.77	Feb	7.37	Feb	8.10	Feb	6.17
Mar	14.33	Mar	14.03	Mar	10.11	Mar	8.84	Mar	7.72	Mar	8.14	Mar	6.01
Apr	13.50	Apr	14.30	Apr	10.53	Apr	8.79	Apr	7.88	Apr	8.14	Apr	6.38
May	12.17	May	14.95	May	10.75	May	8.72	May	7.99	May	8.55	May	6.68
Jun	11.87	Jun	15.16	Jun	10.71	Jun	8.64	Jun	8.07	Jun	8.22	Jun	6.53
Jul	12.12	Jul	14.92	Jul	10.96	Jul	8.46	Jul	8.02	Jul	8.17	Jul	6.34
Aug	12.82	Aug	14.29	Aug	11.09	Aug	8.34	Aug	7.84	Aug	8.05	Aug	6.18
Sep	13.29	Sep	14.04	Sep	10.56	Sep	8.32	Sep	8.01	Sep	8.16	Sep	6.01
Oct	13.53	Oct	13.68	Oct	9.92	Oct	8.44	Oct	7.76	Oct	8.08	Oct	5.95
Nov	14.07	Nov	13.15	Nov	9.89	Nov	8.53	Nov	7.48	Nov	8.03	Nov	5.97
Dec	14.48	Dec	12.96	Dec	10.02	Dec	8.36	Dec	7.58	Dec	7.79	Dec	5.93
Jan 1981	14.22	Jan 1985	12.88	Jan 1989	10.02	Jan 1993	8.23	Jan 1997	7.79	Jan 2001	7.76	Jan 2005	5.80
Feb	14.84	Feb	13.00	Feb	10.02	Feb	8.00	Feb	7.68	Feb	7.69	Feb	5.64
Mar	14.86	Mar	13.66	Mar	10.16	Mar	7.85	Mar	7.92	Mar	7.59	Mar	5.86
Apr	15.32	Apr	13.42	Apr	10.14	Apr	7.76	Apr	8.08	Apr	7.81	Apr	5.72
May	15.84	May	12.89	May	9.92	May	7.78	May	7.94	May	7.88	May	5.60
Jun	15.27	Jun	11.91	Jun	9.49	Jun	7.68	Jun	7.77	Jun	7.75	Jun	5.39
Jul	15.87	Jul	11.88	Jul	9.34	Jul	7.53	Jul	7.52	Jul	7.71	Jul	5.50
Aug	16.33	Aug	11.93	Aug	9.37	Aug	7.21	Aug	7.57	Aug	7.57	Aug	5.51
Sep	16.89	Sep	11.95	Sep	9.43	Sep	7.01	Sep	7.50	Sep	7.73	Sep	5.54
Oct	16.76	Oct	11.84	Oct	9.37	Oct	6.99	Oct	7.37	Oct	7.64	Oct	5.79
Nov	15.50	Nov	11.33	Nov	9.33	Nov	7.30	Nov	7.24	Nov	7.61	Nov	5.88
Dec	15.77	Dec	10.82	Dec	9.31	Dec	7.33	Dec	7.16	Dec	7.86	Dec	5.83
Jan 1982	16.73	Jan 1986	10.66	Jan 1990	9.44	Jan 1994	7.31	Jan 1998	7.03	Jan 2002	7.69	Jan 2006	5.77
Feb	16.72	Feb	10.16	Feb	9.66	Feb	7.44	Feb	7.09	Feb	7.62	Feb	5.83
Mar	16.07	Mar	9.33	Mar	9.75	Mar	7.83	Mar	7.13	Mar	7.83	Mar	5.98
Apr	15.82	Apr	9.02	Apr	9.87	Apr	8.20	Apr	7.12	Apr	7.74	Apr	6.28
May	15.60	May	9.52	May	9.89	May	8.32	May	7.11	May	7.76	May	6.39
Jun	16.18	Jun	9.51	Jun	9.69	Jun	8.31	Jun	6.99	Jun	7.67	June	6.39
Jul	16.04	Jul	9.19	Jul	9.66	Jul	8.47	Jul	6.99	Jul	7.54	Jul	6.37
Aug	15.22	Aug	9.15	Aug	9.84	Aug	8.41	Aug	6.96	Aug	7.34	Aug	6.20
Sep	14.56	Sep	9.42	Sep	10.01	Sep	8.65	Sep	6.88	Sep	7.23	Sep	6.03
Oct	13.88	Oct	9.39	Oct	9.94	Oct	8.88	Oct	6.88	Oct	7.43	Oct	6.01
Nov	13.58	Nov	9.15	Nov	9.76	Nov	9.00	Nov	6.96	Nov	7.31	Nov	5.82
Dec	13.55	Dec	8.96	Dec	9.57	Dec	8.79	Dec	6.84	Dec	7.20	Dec	5.83
Jan 1983	13.46	Jan 1987	8.77	Jan 1991	9.56	Jan 1995	8.77	Jan 1999	6.87	Jan 2003	7.13	Jan 2007	5.96
Feb	13.60	Feb	8.81	Feb	9.31	Feb	8.56	Feb	7.00	Feb	6.92	Feb	5.91
Mar	13.28	Mar	8.75	Mar	9.39	Mar	8.41	Mar	7.18	Mar	6.80	Mar	5.87
Apr	13.03	Apr	9.30	Apr	9.30	Apr	8.30	Apr	7.16	Apr	6.68	Apr	6.01
May	13.00	May	9.82	May	9.29	May	7.93	May	7.42	May	6.35	May	6.03
Jun	13.17	Jun	9.87	Jun	9.44	Jun	7.62	Jun	7.70	Jun	6.21	Jun	6.34
Jul	13.28	Jul	10.01	Jul	9.40	Jul	7.73	Jul	7.66	Jul	6.54	July	6.28
Aug	13.50	Aug	10.33	Aug	9.16	Aug	7.86	Aug	7.86	Aug	6.78	Aug	6.28
Sep	13.35	Sep	11.00	Sep	9.03	Sep	7.62	Sep	7.87	Sep	6.58	Sep	6.24
Oct	13.19	Oct	11.32	Oct	8.99	Oct	7.46	Oct	8.02	Oct	6.50	Oct	6.17
Nov	13.33	Nov	10.82	Nov	8.93	Nov	7.40	Nov	7.86	Nov	6.44	Nov	6.04
Dec	13.48	Dec	10.99	Dec	8.76	Dec	7.21	Dec	8.04	Dec	6.36	Dec	6.23

Source:
Mergent Bond Record for May 2007 PU Bonds (page 16)

SCHEDULE 5-1

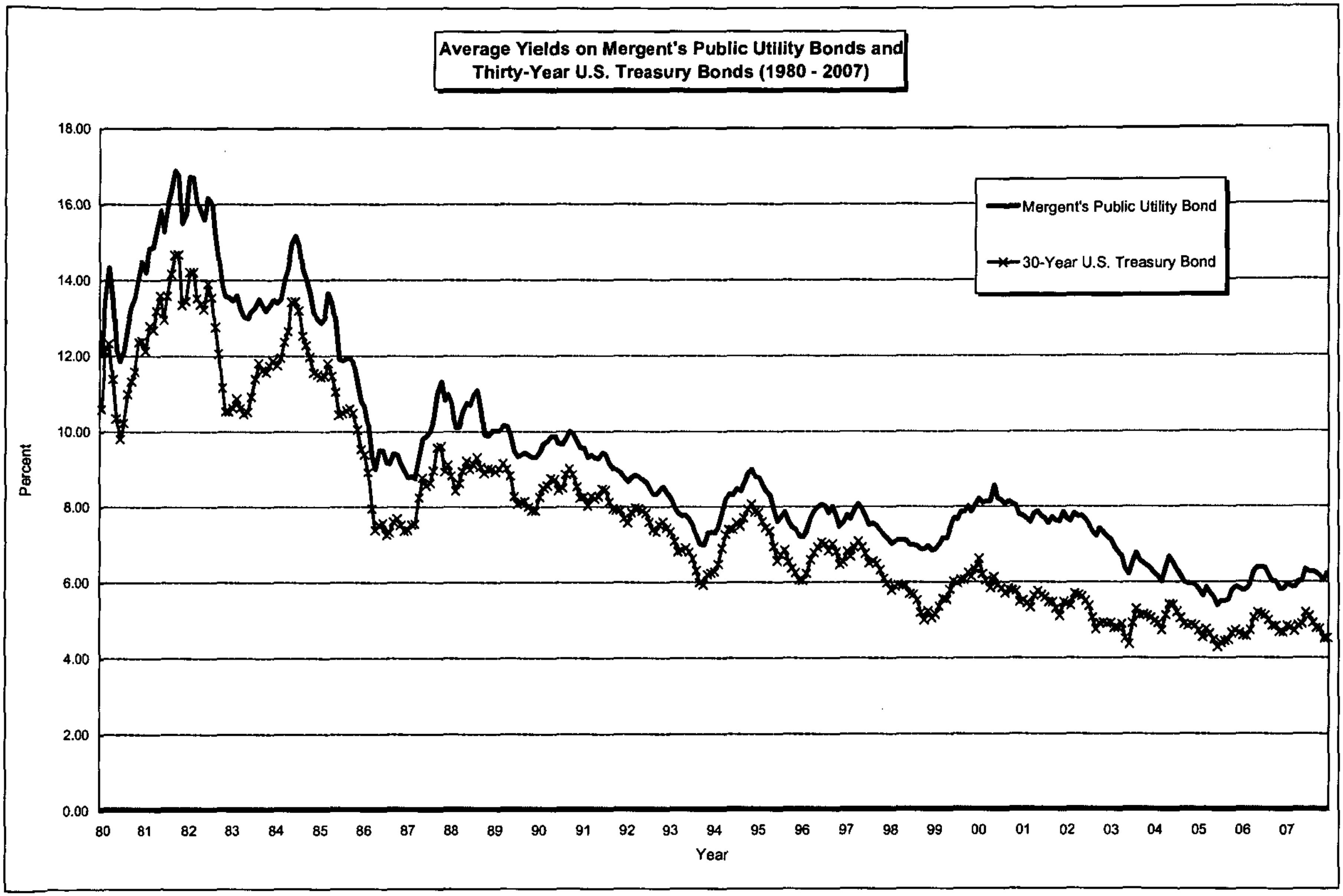
The Empire District Electric Company
Case No. ER-2008-0093

Average Yields on Thirty-Year U.S. Treasury Bonds

Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)	Mo/Year	Rate (%)
Jan 1980	10.60	Jan 1984	11.75	Jan 1988	8.83	Jan 1992	7.58	Jan 1996	6.05	Jan 2000	6.63	Jan 2004	4.99
Feb	12.13	Feb	11.95	Feb	8.43	Feb	7.85	Feb	6.24	Feb	6.23	Feb	4.93
Mar	12.34	Mar	12.38	Mar	8.63	Mar	7.97	Mar	6.60	Mar	6.05	Mar	4.74
Apr	11.40	Apr	12.65	Apr	8.95	Apr	7.96	Apr	6.79	Apr	5.85	Apr	5.14
May	10.36	May	13.43	May	9.23	May	7.89	May	6.93	May	6.15	May	5.42
Jun	9.81	Jun	13.44	Jun	9.00	Jun	7.84	Jun	7.06	Jun	5.93	Jun	5.41
Jul	10.24	Jul	13.21	Jul	9.14	Jul	7.60	Jul	7.03	Jul	5.85	Jul	5.22
Aug	11.00	Aug	12.54	Aug	9.32	Aug	7.39	Aug	6.84	Aug	5.72	Aug	5.06
Sep	11.34	Sep	12.29	Sep	9.06	Sep	7.34	Sep	7.03	Sep	5.83	Sep	4.90
Oct	11.59	Oct	11.98	Oct	8.89	Oct	7.53	Oct	6.81	Oct	5.80	Oct	4.86
Nov	12.37	Nov	11.56	Nov	9.02	Nov	7.61	Nov	6.48	Nov	5.78	Nov	4.89
Dec	12.40	Dec	11.52	Dec	9.01	Dec	7.44	Dec	6.55	Dec	5.49	Dec	4.86
Jan 1981	12.14	Jan 1985	11.45	Jan 1989	8.93	Jan 1993	7.34	Jan 1997	6.83	Jan 2001	5.54	Jan 2005	4.73
Feb	12.80	Feb	11.47	Feb	9.01	Feb	7.09	Feb	6.69	Feb	5.45	Feb	4.55
Mar	12.69	Mar	11.81	Mar	9.17	Mar	6.82	Mar	6.93	Mar	5.34	Mar	4.78
Apr	13.20	Apr	11.47	Apr	9.03	Apr	6.85	Apr	7.09	Apr	5.65	Apr	4.65
May	13.60	May	11.05	May	8.83	May	6.92	May	6.94	May	5.78	May	4.49
Jun	12.96	Jun	10.44	Jun	8.27	Jun	6.81	Jun	6.77	Jun	5.67	Jun	4.29
Jul	13.59	Jul	10.50	Jul	8.08	Jul	6.63	Jul	6.51	Jul	5.61	Jul	4.41
Aug	14.17	Aug	10.56	Aug	8.12	Aug	6.32	Aug	6.58	Aug	5.48	Aug	4.46
Sep	14.67	Sep	10.61	Sep	8.15	Sep	6.00	Sep	6.50	Sep	5.48	Sep	4.47
Oct	14.68	Oct	10.50	Oct	8.00	Oct	5.94	Oct	6.33	Oct	5.32	Oct	4.67
Nov	13.35	Nov	10.06	Nov	7.90	Nov	6.21	Nov	6.11	Nov	5.12	Nov	4.73
Dec	13.45	Dec	9.54	Dec	7.90	Dec	6.25	Dec	5.99	Dec	5.48	Dec	4.66
Jan 1982	14.22	Jan 1986	9.40	Jan 1990	8.26	Jan 1994	6.29	Jan 1998	5.81	Jan 2002	5.44	Jan 2006	4.59
Feb	14.22	Feb	8.93	Feb	8.50	Feb	6.49	Feb	5.89	Feb	5.39	Feb	4.58
Mar	13.53	Mar	7.96	Mar	8.56	Mar	6.91	Mar	5.95	Mar	5.71	Mar	4.73
Apr	13.37	Apr	7.39	Apr	8.76	Apr	7.27	Apr	5.92	Apr	5.67	Apr	5.06
May	13.24	May	7.52	May	8.73	May	7.41	May	5.93	May	5.64	May	5.20
Jun	13.92	Jun	7.57	Jun	8.46	Jun	7.40	Jun	5.70	Jun	5.52	Jun	5.16
Jul	13.55	Jul	7.27	Jul	8.50	Jul	7.58	Jul	5.68	Jul	5.38	Jul	5.13
Aug	12.77	Aug	7.33	Aug	8.86	Aug	7.49	Aug	5.54	Aug	5.08	Aug	5.00
Sep	12.07	Sep	7.62	Sep	9.03	Sep	7.71	Sep	5.20	Sep	4.76	Sep	4.85
Oct	11.17	Oct	7.70	Oct	8.86	Oct	7.94	Oct	5.01	Oct	4.93	Oct	4.85
Nov	10.54	Nov	7.52	Nov	8.54	Nov	8.08	Nov	5.25	Nov	4.95	Nov	4.69
Dec	10.54	Dec	7.37	Dec	8.24	Dec	7.87	Dec	5.06	Dec	4.92	Dec	4.68
Jan 1983	10.63	Jan 1987	7.39	Jan 1991	8.27	Jan 1995	7.85	Jan 1999	5.16	Jan 2003	4.94	Jan 2007	4.86
Feb	10.88	Feb	7.54	Feb	8.03	Feb	7.61	Feb	5.37	Feb	4.81	Feb	4.82
Mar	10.63	Mar	7.55	Mar	8.29	Mar	7.45	Mar	5.58	Mar	4.80	Mar	4.72
Apr	10.48	Apr	8.25	Apr	8.21	Apr	7.36	Apr	5.55	Apr	4.90	Apr	4.86
May	10.53	May	8.78	May	8.27	May	6.95	May	5.81	May	4.53	May	4.90
Jun	10.93	Jun	8.57	Jun	8.47	Jun	6.57	Jun	6.04	Jun	4.37	Jun	5.20
Jul	11.40	Jul	8.64	Jul	8.45	Jul	6.72	Jul	5.98	Jul	4.93	July	5.11
Aug	11.82	Aug	8.97	Aug	8.14	Aug	6.86	Aug	6.07	Aug	5.30	Aug	4.93
Sep	11.63	Sep	9.59	Sep	7.95	Sep	6.55	Sep	6.07	Sep	5.14	Sep	4.79
Oct	11.58	Oct	9.61	Oct	7.93	Oct	6.37	Oct	6.26	Oct	5.16	Oct	4.78
Nov	11.75	Nov	8.95	Nov	7.92	Nov	6.26	Nov	6.15	Nov	5.13	Nov	4.52
Dec	11.88	Dec	9.12	Dec	7.70	Dec	6.06	Dec	6.35	Dec	5.08	Dec	4.53

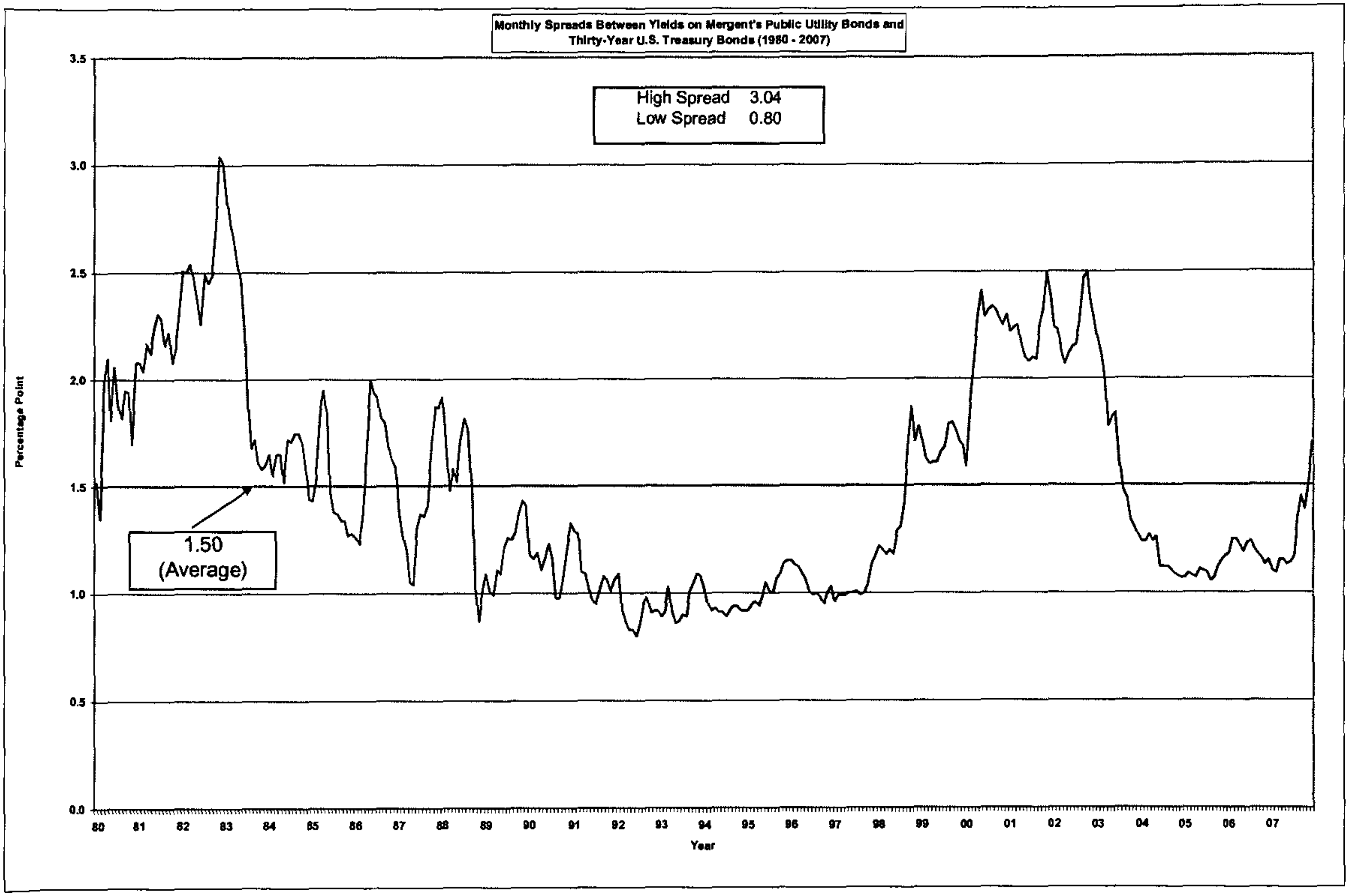
Sources:
http://finance.yahoo.com/q/hp?s=^TYX

The Empire District Electric Company
Case No. ER-2008-0093



SCHEDULE 5-3

The Empire District Electric Company
Case No. ER-2008-0093



SCHEDULE 5-4

The Empire District Electric Company
Case No. ER-2008-0093

Economic Estimates and Projections, 2007-2009

Source	Inflation Rate 2007	Inflation Rate 2008	Inflation Rate 2009	Real GDP 2007	Real GDP 2008	Real GDP 2009	Unemployment 2007	Unemployment 2008	Unemployment 2009	3-Mo. T-Bill Rate 2007	3-Mo. T-Bill Rate 2008	3-Mo. T-Bill Rate 2009	30-Year T-Bond Rate 2007	30-Year T-Bond Rate 2008	30-Year T-Bond Rate 2009
Value Line Investment Survey -- Selection & Opinion (05-25-07, page 4707)	3.90%	2.00%	2.30%	2.10%	2.00%	3.00%	4.60%	5.00%	4.90%	4.50%	3.30%	4.70%	4.80%	4.70%	5.20%
The Budget and Economic Outlook FY2008-2018	2.80%	2.90%	2.30%	2.20%	1.70%	2.80%	4.60%	5.10%	5.40%	4.40%	3.20%	4.20%	N/A	N/A	N/A
Current rate	4.10%			4.90%			5.00%			3.00%			4.28%		

Notes: N.A. = Not Available.
Value Line data for 2007-2009 are estimated.
CBO data for 2007 are estimated, data for 2008 and 2009 is projected.

Sources of Current Rates:

Inflation:	The Bureau of Labor Statistics, Consumer Price Index - All Urban Consumers, 12-Month Period Ending, December 31, 2007 (see first paragraph).
	http://www.bls.gov/schedule/archives/cpi_nr.htm
GDP:	U.S. Department of Commerce, Bureau of Economic Analysis for the Quarter Ending September 31, 2007 (see first paragraph).
	http://www.bea.gov/newsreleases/national/gdp/gdpnewsrelease.htm
Unemployment:	The Bureau of Labor Statistics, Economy Situation Summary - Unemployment Rate, December 2007.
	http://www.bls.gov/news.release/empsit.nr0.htm
3-Month Treasury:	St. Louis Federal Reserve website for December 1, 2007.
	http://research.stlouisfed.org/fred2/series/TB3MS/22
30-Yr. T-Bond:	Yahoo Finance Website for January 28, 2008.
	http://finance.yahoo.com/q?s=%5ETYX
Other Sources (2007 - 2009):	ValueLine Investment Survey Selection & Opinion, November 23, 2007, page 4414.
	The Congressional Budget Office, The Budget and Economic Outlook: Fiscal Years 2008-2018, January 2008.
	http://www.cbo.gov/publications/bysubject.cfm?cat=0

The Empire District Company
Case No. ER-2008-0093

Historical Consolidated Capital Structures for The Empire District Electric Company

Capital Components	2003		2004		2005		2006		2007		5-Year Average
Common Equity	$378,824,831.0		$379,180,390.0		$393,411,000.0		$468,609,000.0		$539,175,775.0		$431,840,199.2
Preferred Stock	0.0		0.0		0.0		0.0		0.0		$0.0
Long-Term Debt	410,821,760.0	*	410,378,837.0	*	408,173,000.0	*	462,670,000.0	*	521,878,483.0	*	$442,784,416.0
Short-Term Debt	13,000,000.0		0.0		30,952,000.0		77,050,000.0		0.0		$24,200,400.0
Total	$802,646,591.0		$789,559,227.0		$832,536,000.0		$1,008,329,000.0		$1,061,054,258.0		$898,825,015.2

Capital Components	2003	2004	2004	2005	2006	5-Year Average
Common Equity	47.20%	48.02%	47.25%	46.47%	50.82%	47.95%
Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Long-Term Debt	51.18%	51.98%	49.03%	45.88%	49.18%	49.45%
Short-Term Debt	1.62%	0.00%	3.72%	7.64%	0.00%	2.60%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Source: Response to Staff Data Request No. 0112

The Empire District Electric 2004 Annual Report.
The Empire District Electric 2006 Annual Report.

Note: *Includes current maturities of long-term debt and preferred stock.

SCHEDULE 7

The Empire District Electric Company
Case No. ER-2008-0098

Selected Financial Ratios for The Empire District Electric Company

Financial Ratios	2003	2004	2005	2006	2007	
Return on Common Equity	7.80%	5.80%	6.00%	8.50%	7.00%	*
Earnings Per Common Share	$1.29	$0.86	$0.92	$1.41	$1.25	*
Cash Dividends Per Common Share	$1.28	$1.28	$1.28	$1.28	$1.28	*
Common Dividend Payout Ratio	99.22%	148.84%	139.13%	90.78%	102.40%	*
Year-End Market Price Per Common Share	$21.93	$22.68	$20.33	$24.69	$22.78	
Year-End Book Value Per Common Share	$15.17	$14.76	$15.08	$15.49	$16.10	*
Year-End Market-to-Book Ratio	1.45 x	1.54 x	1.35 x	1.59 x	1.41 x	*
Funds From Operations (FFO) Interest Coverage Ratio	3.6 x	3.1 x	3.9 x	3.4 x	4.2 x	**
FFO/Average Total Debt	21%	18%	17%	15%	18%	**
Corporate Credit Rating (Standard & Poor's Corporation)	BBB	BBB	BBB	BBB	BBB-	

Formulas:

Common Dividend Payout Ratio = Common Dividends Paid / Earnings Per Common Share.

Year-End Market-to-Book Ratio = Year-End Market Price Per Common Share / Year-End Book Value Per Common Share.

*2007 Estimate.
** As of September 30, 2007 (End of Third Quarter)

Sources: Standard and Poor's Empire Research Update March 17, 2007.
Standard and Poor's CreditStats, August 11, 2005.
Standard and Poor's CreditStats, September 10, 2007.
Standard and Poor's Stock Guide, January 2004, January 2005, January 2006, January 2007, and January 2008.
Value Line Investment Survey for The Empire District Electric Company, December 28, 2007.

SCHEDULE 8

The Empire District Electric Company
Case No. ER-2008-0093

Capital Structure as of December 31, 2007
The Empire District Electric Company

Capital Component	Dollar Amount	Percentage of Capital
Common Stock Equity	$ 539,175,775	50.82%
Trust Preferred Stock	$ 48,544,208	4.58%
Long-Term Debt	$ 473,334,275	44.61%
Short-Term Debt	$ -	0.00%
Total Capitalization	**$ 1,061,054,258**	**100.00%**

Electric Financial Ratio Benchmark
Total Debt / Total Capital

Standard & Poor's Corporation's RatingsDirect, "U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix", November 30, 2007.	BBB- Credit Rating based on a "Aggressive" Financial Risk Profile 45% to 60%

Notes: 1. Long-term Debt at December, 2007 is based on the net balance of long-term debt, including current maturities (total principal amount of long-term debt outstanding less unamortized expenses and discounts) shown on Schedule 10. This balance also includes the amoun of non-regulated debt.

2. Short-term debt balance net of construction work in progress (CWIP) was negative as of December 31, 2007. Therefore, no short-term debt is included in the capital structure.

Source: Response to Staff Data Request No. 0112.

The Empire District Electric Company
ER-2008-0093

Embedded Cost of Long-Term Debt as of December 31, 2007

	Amount Outstanding	Annual Cost
Bonds and Unsecured Notes Series:		
7.2% Series, Due 2016	$25,000,000	$1,800,000
5.2% Pollution Control Series, Due 2013	$5,200,000	$270,400
5.3% Pollution Control Series, Due 2013	$8,000,000	$424,000
7.05% Series, Due 2022	$49,289,000	$3,474,875
6.7% Series, Due 2033	$62,000,000	$4,154,000
5.8% Series, Due 7/1/2035	$40,000,000	$2,320,000
8-1/8 Series, Due 2009	$20,000,000	$1,625,000
6-1/2 Series, Due 2010	$50,000,000	$3,250,000
4.5% Series, Due 2013	$98,000,000	$4,410,000
5.875%, Due 2037	$80,000,000	$4,700,000
6.82% Series, Due 6/1/2036-EDG	$55,000,000	$3,751,000
Premium, Discount and Expense	-$19,305,162	$1,984,531
Total	**$473,183,838**	**$32,163,806**
Embedded Cost of Long-term Debt		**6.80%**

Source: Response to Staff Data Request 0112.

The Empire District Electric Company
ER-2008-0093

Embedded Cost of Trust Preferred Stock
as of December 31, 2008

	Amount Outstanding	Annual Cost
Trust Preferred Series:		
Trust Preferred	$50,000,000	$4,250,000
Premium, Discount and Expense	-$1,455,792	$62,840
Total	**$48,544,208**	**$4,312,840**
Embedded Cost of Long-term Debt		**8.88%**

Source: Response to Staff Data Request 0112.

The Empire District Electric Company
Case No. ER-2008-0093

Criteria for Selecting Comparable Electric Utility Companies

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
ValueLine Electric Utility Companies(Ticker)	Stock Publicly Traded	Information Printed in ValueLine	10-Years of Data Available	% Electric Revenues ≥ 70%	No Pending Merger in the last 6 months	No Cut Dividend in the last 10 years	Two Sources for Projected Growth Available with One from Value Line	At Least Investment Grade Credit Rating	**Comparable Company Met All Criteria**
ALLETE(ALE)	Yes	Yes	No						
Allegheny Energy(AYE)	Yes	Yes	Yes	Yes	Yes	No			
Alliant Energy(LNT)	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Ameren Corp.(AEE)	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
American Electric Power(AEP)	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Aquila, Inc.(ILA)	Yes	Yes	Yes	No					
Avista Corp.(AVA)	Yes	Yes	Yes	No					
Black Hills(BKH)	Yes	Yes	Yes	No					
CenterPoint Energy(CNP)	Yes	Yes	No						
Central Vermont Public Service(CV)	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	
CH Energy Group(CHG)	Yes	Yes	Yes	No					
Cleco Corp.(CNL)	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
CMS Energy Corp.(CMS)	Yes	Yes	Yes	No	Yes	No			
Consolidated Edison(ED)	Yes	Yes	Yes	No					
Constellation Energy(CEG)	Yes	Yes	Yes	No					
Dominion Resources (D)	Yes	Yes	Yes	No					
DPL Inc.(DPL)	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
DTE Energy(DTE)	Yes	Yes	Yes	No					
Duke Energy(DUK)	Yes	Yes	No						
Edison International(EIX)	Yes	Yes	Yes	Yes	Yes	No			
El Paso Electric(EE)	Yes	Yes	Yes	Yes	Yes	No			
Energy East Corp.(EAS)	Yes	Yes	Yes	No					
Entergy Corp.(ETR)	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Evergreen Energy Inc.(EEE)	Yes	Yes	No						
Excel Energy Inc.(XEL)	Yes	Yes	No						
Exelon Corp.(EXC)	Yes	Yes	No						
FirstEnergy Corp.(FE)	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Florida Public Utilities(FPU)	Yes	Yes	No						
FPL Group(FPL)	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Great Plains Energy (GXP)	Yes	Yes	Yes	No					
Hawaiian Electric(HE)	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
IDACORP, Inc.(IDA)	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Integrys Energy(TEG)	Yes	Yes	Yes	No					
Maine & Maritimes Corp.(MAM)	Yes	Yes	No						
MDU Resources(MDU)	Yes	Yes	Yes	No					
MGE Energy(MGEE)	Yes	Yes	Yes	No					
NiSource Inc.(NI)	Yes	Yes	Yes	No					
Northeast Utilities(NU)	Yes	Yes	Yes	Yes	Yes	No			
NSTAR(NST)	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
OGE Energy(OGE)	Yes	Yes	Yes	No					
Otter Tail Corp.(OTTR)	Yes	Yes	Yes	No					
Pepco Holdings(POM)	Yes	Yes	No						
PG&E Corp.(PCG)	Yes	Yes	Yes	Yes	Yes	No			
Pinnacle West Capital(PNW)	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
PNM Resources(PNM)	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Portland General(POR)	Yes	Yes	No						
PPL Corp.(PPL)	Yes	Yes	Yes	No					
Progress Energy(PGN)	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Public Service Enterprise(PEG)	Yes	Yes	Yes	No					
Puget Energy Inc.(PSD)	Yes	Yes	Yes	No					
SCANA Corp.(SCG)	Yes	Yes	Yes	No					
Sempra Energy(SRE)	Yes	Yes	Yes	No					
Sierra Pacific Resources(SRP)	Yes	Yes	Yes	Yes	Yes	No			
Southern Company(SO)	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
TECO Energy(TE)	Yes	Yes	Yes	No					
UIL Holdings(UIL)	Yes	Yes	Yes	Yes	Yes	Yes	Yes	N.A.	
UniSource Energy(UNS)	Yes	Yes	Yes	Yes	Yes	No			
UNITIL Corp.(UTL)	Yes	Yes	No						
Vectren Corp.(VVC)	Yes	Yes	No						
Westar Energy(WR)	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Wisconsin Energy(WEC)	Yes	Yes	Yes	No					

Sources: Columns 1, 2 and 5 = Standard & Poor's RatingsDirect.
Columns 3, 4 and 6 = The Value Line Investment Survey: Ratings & Reports, November 30, December 28, 2007 and February 08, 2008.

Columnn 6 = I/B/E/S Inc.'s Institutional Brokers Estimate System, January 17, 2008.

Notes: N.A. = Not available.

The Empire District Electric Company
Case No. ER-2008-0093

Comparable Electrical Utility Companies
for The Empire District Electric Company

Number	Ticker Symbol	Company Name
1	LNT	Alliant Energy
2	AEE	Ameren Corp.
3	PNW	American Electric Power
4	CNL	Cleco Corp.
5	DPL	DPL Inc.
6	ETR	Entergy Corp.
7	FE	FirstEnergy Corp.
8	FPL	FPL Group
9	HE	Hawaiian Electric
10	IDA	IDACORP, Inc.
11	NST	NSTAR
12	PNW	Pinnacle West Capital
13	PNM	PNM Resources
14	PGN	Progress Energy
15	SO	Southern Company
16	WR	Westar Energy

The Empire District Electric Company
Case No. ER-2008-0093

Ten-Year Dividends Per Share, Earnings Per Share & Book Value Per Share Growth Rates for the Comparable Electric Utility Companies and The Empire District Electric Company

	----- 10-Year Annual Compound Growth Rate -----			
Company Name	DPS	EPS	BVPS	Average of 10-Year Annual Compound Growth Rates
Alliant Energy	-6.00%	-1.00%	1.00%	-2.00%
Ameren Corp.	0.50%	0.00%	3.00%	1.17%
American Electric Power	-5.00%	-0.50%	-0.50%	-2.00%
Cleco Corp.	2.00%	3.00%	5.50%	3.50%
DPL Inc.	1.50%	1.50%	0.50%	1.17%
Entergy Corp.	1.50%	8.50%	3.00%	4.33%
FirstEnergy Corp.	2.00%	4.50%	5.50%	4.00%
FPL Group	4.50%	5.50%	6.50%	5.50%
Hawaiian Electric	0.50%	0.50%	1.50%	0.83%
IDACORP, Inc.	-4.50%	0.00%	3.00%	-0.50%
NSTAR	2.50%	4.50%	3.50%	3.50%
Pinnacle West Capital	7.50%	2.00%	4.50%	4.67%
PNM Resources	0.00%	4.00%	6.00%	3.33%
Progress Energy	3.00%	1.00%	6.50%	3.50%
Southern Company	2.00%	2.50%	1.00%	1.83%
Westar Energy	-8.00%	-5.00%	-4.00%	-5.67%
Average	0.25%	1.94%	2.91%	1.70%
Standard Deviation	3.98%	3.04%	2.81%	2.91%
The Empire District Electric Company	**0.00%**	**-1.50%**	**1.50%**	**0.00%**

Source: The Value Line Investment Survey: Ratings & Reports, November 30, December 28, 2007 and February 08, 2008.

SCHEDULE 14-1

The Empire District Electric Company
Case No. ER-2008-0093

Five-Year Dividends Per Share, Earnings Per Share & Book Value Per Share Growth Rates for the Comparable Electric Utility Companies and The Empire District Electric Company

	---- 5-Year Annual Compound Growth Rates ----			
Company Name	DPS	EPS	BVPS	Average of 5-Year Annual Compound Growth Rates
Alliant Energy	-11.50%	-3.00%	-2.50%	-5.67%
Ameren Corp.	0.00%	-2.00%	5.50%	1.17%
American Electric Power	-9.50%	3.00%	-2.50%	-3.00%
Cleco Corp.	1.00%	0.00%	5.50%	2.17%
DPL Inc.	0.50%	-3.50%	0.50%	-0.83%
Entergy Corp.	11.00%	10.50%	4.00%	8.50%
FirstEnergy Corp.	4.00%	3.50%	4.50%	4.00%
FPL Group	5.50%	4.50%	6.50%	5.50%
Hawaiian Electric	0.00%	-1.00%	2.00%	0.33%
IDACORP, Inc.	-8.50%	-8.50%	2.50%	-4.83%
NSTAR	3.00%	3.50%	2.50%	3.00%
Pinnacle West Capital	6.00%	-5.00%	4.00%	1.67%
PNM Resources	7.50%	-2.50%	4.50%	3.17%
Progress Energy	2.50%	-0.50%	5.00%	2.33%
Southern Company	2.00%	3.00%	1.00%	2.00%
Westar Energy	-11.00%	21.00%	-9.00%	0.33%
Average	**0.16%**	**1.44%**	**2.13%**	**1.24%**
Standard Deviation	6.59%	6.67%	3.87%	3.51%
The Empire District Electric Company	**0.00%**	**1.00%**	**2.00%**	**1.00%**

Source: The Value Line Investment Survey: Ratings & Reports, November 30, December 28, 2007 and February 08, 2008.

SCHEDULE 14-2

The Empire District Electric Company
Case No. ER-2008-0093

Average of Ten- and Five-Year Dividends Per Share, Earnings Per Share, and Book Value Per Share for the Comparable Electric Utility Companies and The Empire District Electric Company

Company Name	10-Year Average DPS, EPS & BVPS	5-Year Average DPS, EPS & BVPS	Average of 5-Year & 10-Year Averages
Alliant Energy	-2.00%	-5.67%	-3.83%
Ameren Corp.	1.17%	1.17%	1.17%
American Electric Power	-2.00%	-3.00%	-2.50%
Cleco Corp.	3.50%	2.17%	2.83%
DPL Inc.	1.17%	-0.83%	0.17%
Entergy Corp.	4.33%	8.50%	6.42%
FirstEnergy Corp.	4.00%	4.00%	4.00%
FPL Group	5.50%	5.50%	5.50%
Hawaiian Electric	0.83%	0.33%	0.58%
IDACORP, Inc.	-0.50%	-4.83%	-2.67%
NSTAR	3.50%	3.00%	3.25%
Pinnacle West Capital	4.67%	1.67%	3.17%
PNM Resources	3.33%	3.17%	3.25%
Progress Energy	3.50%	2.33%	2.92%
Southern Company	1.83%	2.00%	1.92%
Westar Energy	-5.67%	0.33%	-2.67%
Average	**1.70%**	**1.24%**	**1.47%**
The Empire District Electric Company	**0.00%**	**1.00%**	**0.50%**

SCHEDULE 14-3

The Empire District Electric Company
Case No. ER-2008-0093

Historical and Projected Growth Rates
for the Comparable Electric Utility Companies
and The Empire District Electric Company

	(1)	(2)	(3)	(4)	(5)	(6)
Company Name	Historical Growth Rate (DPS, EPS and BVPS)	Projected 5-Year EPS Growth IBES (Mean)	Projected 5-Year EPS Growth S&P	Projected 3-5 Year EPS Growth Value Line	Average Projected Growth	Average of Historical & Projected Growth
Alliant Energy	-3.83%	6.00%	6.00%	5.50%	5.83%	1.00%
Ameren Corp.	1.17%	7.30%	6.00%	3.00%	5.43%	3.30%
American Electric Power	-2.50%	6.02%	6.00%	6.50%	6.17%	1.84%
Cleco Corp.	2.83%	14.00%	14.00%	6.50%	11.50%	7.17%
DPL Inc.	0.17%	8.88%	9.00%	10.50%	9.46%	4.81%
Entergy Corp.	6.42%	10.60%	11.00%	9.50%	10.37%	8.39%
FirstEnergy Corp.	4.00%	11.00%	9.00%	9.00%	9.67%	6.83%
FPL Group	5.50%	9.90%	10.00%	11.00%	10.30%	7.90%
Hawaiian Electric	0.58%	8.53%	9.00%	1.50%	6.34%	3.46%
IDACORP, Inc.	-2.67%	6.00%	6.00%	2.00%	4.67%	1.00%
NSTAR	3.25%	6.50%	7.00%	8.50%	7.33%	5.29%
Pinnacle West Capital	3.17%	5.73%	6.00%	1.50%	4.41%	3.79%
PNM Resources	3.25%	9.13%	9.00%	2.50%	6.88%	5.06%
Progress Energy	2.92%	5.04%	5.00%	3.50%	4.51%	3.72%
Southern Company	1.92%	5.03%	5.00%	3.00%	4.34%	3.13%
Westar Energy	-2.67%	5.58%	6.00%	4.50%	5.36%	1.35%
Average	**1.47%**	**7.83%**	**7.75%**	**5.53%**	**7.04%**	**4.25%**
The Empire District Electric Company	**0.50%**	**0.00%** *	**0.00%** *	**8.50%**		

Proposed Range of Growth for Comparables: **5.55%-6.70%**

Column 5 = [(Column 2 + Column 3 + Column 4) / 3]

Column 6 = [(Column 1 + Column 5) / 2]

Sources: Column 1 = Average of 10-Year and 5-Year Annual Compound Growth Rates from Schedule 13-3.

Column 2 = I/B/E/S Inc.'s Institutional Brokers Estimate System, January 17, 2008.

Column 3 = Standard & Poor's Earnings Guide, January 2008.

Column 4 = The Value Line Investment Survey: Ratings and Reports, November 30, December 28, 2007 and February 8, 2008.

*IBES and S&P reported a growth rate of 34 percent for Empire. This is an incorrect number and Staff was informed by IBES that the number is being corrected, therefore; Staff could not caclulate a company specific return on equity.

The Empire District Electric Company
Case No. ER-2008-0093

Average High / Low Stock Price for September 2007 through December 2007
for the Comparable Electric Utility Companies and
The Empire District Electric Company

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	-- September 2007 --		-- October 2007 --		-- November 2007 --		-- December 2007 --		**Average High/Low**
Company Name	High Stock Price	Low Stock Price	High Stock Price	Low Stock Price	High Stock Price	Low Stock Price	High Stock Price	Low Stock Price	**Stock Price (09/07 - 12/07)**
Alliant Energy	$39.030	$36.610	$40.570	$37.320	$42.000	$38.880	$43.410	$40.690	**$39.814**
Ameren Corp.	$53.890	$50.250	$54.400	$51.810	$54.200	$51.960	$54.740	$52.840	**$53.011**
American Electric Power	$46.970	$44.060	$48.700	$45.050	$48.230	$45.360	$49.490	$46.320	**$46.773**
Cleco Corp.	$26.030	$22.410	$26.760	$24.500	$29.840	$25.090	$28.760	$24.600	**$25.999**
DPL Inc.	$26.820	$25.980	$29.040	$25.710	$30.480	$28.700	$31.000	$29.200	**$28.366**
Entergy Corp.	$111.950	$102.120	$120.890	$108.210	$125.000	$114.040	$123.390	$114.740	**$115.043**
FirstEnergy Corp.	$66.180	$61.080	$69.920	$63.390	$69.760	$66.310	$74.980	$68.100	**$67.465**
FPL Group	$63.490	$58.230	$68.480	$60.260	$70.140	$65.530	$72.770	$67.520	**$65.803**
Hawaiian Electric	$21.870	$20.620	$23.200	$21.680	$23.490	$20.920	$23.950	$22.600	**$22.291**
IDACORP, Inc.	$33.900	$31.200	$36.450	$32.360	$35.740	$33.000	$36.720	$33.680	**$34.131**
NSTAR	$35.050	$32.450	$35.440	$33.450	$35.620	$33.590	$37.000	$34.860	**$34.683**
Pinnacle West Capital	$40.700	$39.480	$42.620	$39.500	$43.640	$39.040	$44.500	$42.000	**$41.435**
PNM Resources	$23.620	$21.190	$25.210	$23.050	$25.060	$21.710	$23.950	$21.410	**$23.150**
Progress Energy	$48.160	$44.960	$48.000	$44.750	$49.060	$46.310	$50.250	$48.250	**$47.468**
Southern Company	$37.480	$35.040	$37.230	$35.160	$38.750	$35.150	$39.350	$37.360	**$36.940**
Westar Energy	$25.430	$23.500	$26.750	$24.290	$26.760	$24.770	$26.830	$25.280	**$25.451**
The Empire District Electric Company	**$23.270**	**$22.000**	**$24.070**	**$22.220**	**$24.340**	**$22.690**	**$23.500**	**$22.260**	$23.044

Notes:

Column 9 = [(Column 1 + Column 2 + Column 3 + Column 4 + Column 5 + Column 6 + Column 7 + Column 8) / 8].

Sources: S & P Stock Guides: October 2007, November 2007, December 2007 and January 2008.

SCHEDULE 16

The Empire District Electric Company
Case No. ER-2008-0093

Discounted Cash Flow (DCF) Estimated Costs of Common Equity for the Comparable Electric Utility Companies and The Empire District Electric Company

	(1)	(2)	(3)	(4)	(5)
Company Name	Expected Annual Dividend	Average High/Low Stock Price	Projected Dividend Yield	Average of Historical & Projected Growth	Estimated Cost of Common Equity
Alliant Energy	$1.40	$39.814	3.52%	1.00%	4.52%
Ameren Corp.	$2.54	$53.011	4.79%	3.30%	8.09%
American Electric Power	$1.67	$46.773	3.57%	1.84%	5.41%
Cleco Corp.	$0.90	$25.999	3.46%	7.17%	10.63%
DPL Inc.	$1.10	$28.366	3.88%	4.81%	8.69%
Entergy Corp.	$3.10	$115.043	2.69%	8.39%	11.09%
FirstEnergy Corp.	$2.15	$67.465	3.19%	6.83%	10.02%
FPL Group	$1.78	$65.803	2.71%	7.90%	10.61%
Hawaiian Electric	$1.24	$22.291	5.56%	3.46%	9.03%
IDACORP, Inc.	$1.20	$34.131	3.52%	1.00%	4.52%
NSTAR	$1.43	$34.683	4.12%	5.29%	9.41%
Pinnacle West Capital	$2.12	$41.435	5.12%	3.79%	8.90%
PNM Resources	$0.97	$23.150	4.19%	5.06%	9.25%
Progress Energy	$2.47	$47.468	5.20%	3.72%	8.92%
Southern Company	$1.66	$36.940	4.49%	3.13%	7.62%
Westar Energy	$1.16	$25.451	4.56%	1.35%	5.90%
Average			**3.73%**	**4.64%**	**8.36%**
The Empire District Electric Company	**$1.28**	**$23.044**	**5.55%**	**0.00%** *	

Proposed Dividend Yield:	**3.73%**
Proposed Range of Growth:	**5.55% - 6.70%**
Estimated Proxy Cost of Common Equity:	**9.28%-10.43%**
Empire Company-Specific Using Average Projected Growth	*

Notes: Column 1 = Estimated Dividends Declared per share represents the projected dividend for 2008.

Column 3 = (Column 1 / Column 2).

Column 5 = (Column 3 + Column 4).

Sources: Column 1 = The Value Line Investment Survey: Ratings & Reports, November 30, December 28, 2007 and February 08, 2008.

Column 2 = Schedule 15.

Column 4 = Schedule 14.

*IBES and S&P reported a growth rate of 34 percent for Empire. This is an incorrect number and Staff was informed by IBES that the number is being corrected, therefore; Staff could not caclulate a company specific return on equity.

The Empire District Electric Company
Case No. ER-2008-00 93

Capital Asset Pricing Model (CAPM) Costs of Common Equity Estimates
Based on Historical Return Differences Between Common Stocks and Long-Term U.S. Treasuries
for the Comparable Electric Utility Companies and The Empire District Electric Company

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Company Name	Risk Free Rate	Company's Value Line Beta	Arithmetic Average Market Risk Premium (1926-2006)	Geometric Average Market Risk Premium (1926-2006)	Geometric Average Market Risk Premium (1996-2006)	Arithmetic CAPM Cost of Common Equity (1926-2006)	Geometric CAPM Cost of Common Equity (1926-2006)	Geometric CAPM Cost of Common Equity (1996-2006)
Alliant Energy	4.33%	0.80	6.50%	5.00%	0.59%	9.53%	8.33%	4.80%
Ameren Corp.	4.33%	0.80	6.50%	5.00%	0.59%	9.53%	8.33%	4.80%
American Electric Power	4.33%	0.95	6.50%	5.00%	0.59%	10.51%	9.08%	4.89%
Cleco Corp.	4.33%	1.15	6.50%	5.00%	0.59%	11.81%	10.08%	5.01%
DPL Inc.	4.33%	0.85	6.50%	5.00%	0.59%	9.86%	8.58%	4.83%
Entergy Corp.	4.33%	0.85	6.50%	5.00%	0.59%	9.86%	8.58%	4.83%
FirstEnergy Corp.	4.33%	0.85	6.50%	5.00%	0.59%	9.86%	8.58%	4.83%
FPL Group	4.33%	0.75	6.50%	5.00%	0.59%	9.21%	8.08%	4.77%
Hawaiian Electric	4.33%	0.75	6.50%	5.00%	0.59%	9.21%	8.08%	4.77%
IDACORP, Inc.	4.33%	0.95	6.50%	5.00%	0.59%	10.51%	9.08%	4.89%
NSTAR	4.33%	0.75	6.50%	5.00%	0.59%	9.21%	8.08%	4.77%
Pinnacle West Capital	4.33%	0.80	6.50%	5.00%	0.59%	9.53%	8.33%	4.80%
PNM Resources	4.33%	0.90	6.50%	5.00%	0.59%	10.18%	8.83%	4.86%
Progress Energy	4.33%	0.85	6.50%	5.00%	0.59%	9.86%	8.58%	4.83%
Southern Company	4.33%	0.70	6.50%	5.00%	0.59%	8.88%	7.83%	4.74%
Westar Energy	4.33%	0.85	6.50%	5.00%	0.59%	9.86%	8.58%	4.83%
Average		**0.85**				**9.83%**	**8.56%**	**4.83%**
The Empire District Electric Company	**4.33%**	**0.85**	**6.50%**	**5.00%**	**0.59%**	**9.86%**	**8.58%**	**4.83%**

Sources:

Column 1 = The appropriate yield is equal to the average 30-year U.S. Treasury Bond yield for January 2008 which was obtained from the St. Louis Federal Reserve website at http://research.stlouisfed.org/fred2/series/GS30/22.

Column 2 = Beta is a measure of the movement and relative risk of an individual stock to the market as a whole as reported by the Value Line Investment Survey: Ratings & Reports, November 30, December 28, 2007 and February 08, 2008.

Column 3 = The Market Risk Premium represents the expected return from holding the entire market portfolio less the expected return from holding a risk free investment. The appropriate Market Risk Premium for the period 1926 - 2006 was determined to be 6.50% based on an arithmetic average as calculated in Ibbotson Associates, Inc.'s Stocks, Bonds, Bills, and Inflation: 2007 Yearbook.

Column 4 = The Market Risk Premium represents the expected return from holding the entire market portfolio less the expected return from holding a risk free investment. The appropriate Market Risk Premium for the period 1926 - 2006 was determined to be 5.00% based on a geometric average as calculated in Ibbotson Associates, Inc.'s Stocks, Bonds, Bills, and Inflation: 2007 Yearbook.

Column 5 = The Market Risk Premium represents the expected return from holding the entire market portfolio less the expected return from holding a risk free investment. The appropriate Market Risk Premium for the period 1997 - 2006 was determined to be .59% as calculated in Ibbotson Associates, Inc.'s Stocks, Bonds, Bills, and Inflation: 2007 Yearbook.

Column 6 = (Column 1 + (Column 2 * Column 3)).

Column 7 = (Column 1 + (Column 2 * Column 4)).

Column 8 = (Column 1 + (Column 2 * Column 5)).

SCHEDULE 18

The Empire District Electric Company
Case No. ER-2008-0093

Selected Financial Ratios for the Comparable Electric Utility Companies and The Empire District Electric Company

Company Name	(1) 2007 Common Equity Ratio	(2) 2007 Long-Term Debt Ratio	(3) Funds From Operations Interest Coverage	(4) Funds From Operations to Total Debt	(5) Market-to-Book Value	(6) 2007 Return on Common Equity	(7) 2008 Projected Return on Common Equity	(8) Bond Rating
Alliant Energy	56.00%	38.00%	4.70 x	31.0%	1.68 x	12.00%	11.00%	BBB+
Ameren Corp.	54.00%	44.50%	4.00 x	17.5%	1.49 x	10.00%	10.00%	BBB-
American Electric Power	42.00%	58.00%	3.50 x	20.0%	1.86 x	11.00%	12.00%	BBB
Cleco Corp.	54.50%	45.50%	3.00 x	15.0%	1.58 x	8.00%	9.00%	BBB
DPL Inc.	35.50%	63.50%	3.50 x	19.00%	4.06 x	26.50%	26.00%	BBB
Entergy Corp.	43.00%	55.00%	4.00 x	25.00%	2.82 x	14.00%	14.50%	BBB
FirstEnergy Corp.	49.50%	50.50%	4.00 x	18.00%	2.51 x	15.00%	14.00%	BBB
FPL Group	51.00%	49.00%	4.50 x	22.30%	2.47 x	12.90%	13.00%	A
Hawaiian Electric	46.00%	53.00%	3.50 x	16.00%	1.61 x	6.50%	9.00%	BBB
IDACORP, Inc.	52.50%	47.50%	1.80 x	14.10%	1.23 x	7.50%	7.50%	BBB
NSTAR	40.50%	58.50%	4.50 x	26.00%	2.10 x	13.50%	14.00%	A+
Pinnacle West Capital	51.50%	48.50%	4.00 x	17.80%	1.15 x	8.50%	7.00%	BBB-
PNM Resources	49.00%	50.50%	2.20 x	13.40%	0.88 x	5.50%	7.00%	BBB-
Progress Energy	48.00%	51.50%	3.60 x	15.30%	1.41 x	9.00%	9.00%	BBB+
Southern Company	46.00%	51.50%	5.50 x	22.60%	2.37 x	13.50%	13.00%	A
Westar Energy	50.50%	49.00%	3.60 x	16.00%	1.26 x	8.50%	9.00%	BBB-
Average	**48.09%**	**50.88%**	**3.74** x	**19.3%**	**1.91** x	**11.37%**	**11.56%**	**BBB**
The Empire District Electric Company	**50.50%**	**49.50%**	**4.20** x	**18.0%**	**1.40** x	**7.00%**	**8.50%**	**BBB-**

Sources:

The Value Line Investment Survey Ratings & Reports, November 30, December 28, 2007 and February 08, 2008: for columns (1), (2), (6) and (7).
Standard & Poor's RatingsDirect for columns (3), (4).
AUS Utility Reports, February 2008 for column (5).

SCHEDULE 19

The Empire District Electric Company
Case No. ER-2008-0093

Public Utility Revenue Requirement

or

Cost of Service

The formula for the revenue requirement of a public utility may be stated as follows :

Equation 1 : **Revenue Requirement = Cost of Service**

or

Equation 2 : $RR = O + (V - D)R$

The symbols in the second equation are represented by the following factors :

R R	=	Revenue Requirement
O	=	Prudent Operating Costs, including Depreciation and Taxes
V	=	Gross Valuation of the Property Serving the Public
D	=	Accumulated Depreciation
(V - D)	=	Rate Base (Net Valuation)
(V - D) R	=	Return Amount ($$) or Earnings Allowed on Rate Base
R	=	$iL + dP + kE$ or Overall Rate of Return (%)
i	=	Embedded Cost of Debt
L	=	Proportion of Debt in the Capital Structure
d	=	Embedded Cost of Preferred Stock
P	=	Proportion of Preferred Stock in the Capital Structure
k	=	Required Return on Common Equity (ROE)
E	=	Proportion of Common Equity in the Capital Structure

The Empire District Electric Company
Case No. ER-2008-0093

Weighted Cost of Capital as of December 31, 2007 for The Empire District Electric Company

Capital Component	Percentage of Capital	Embedded Cost	Weighted Cost of Capital Using Common Equity Return of: 9.40%	9.98%	10.55%
Common Stock Equity	50.82%		4.78%	5.07%	5.36%
Trust Preferred Stock	4.58%	8.88%	0.41%	0.41%	0.41%
Long-Term Debt	44.61%	6.80%	3.03%	3.03%	3.03%
Short-Term Debt	0.00%				
Total	100.00%		8.22%	8.51%	8.80%

Notes:

See Schedule 9 for the Capital Structure Ratios.

Embedded Cost of Long-Term Debt and Embedded Cost of Preferred Stock Taken from Response to DR 0112.

MISSOURI PUBLIC SERVICE COMMISSION

MATTHEW J. BARNES

ATTACHMENTS A THROUGH E

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2008-0093

MATTHEW J. BARNES

ATTACHMENTS A THROUGH E

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2008-0093

It is generally recognized that authorizing an allowed return on common equity based on a utility's cost of common equity is consistent with a fair rate of return. It is for this very reason that the discounted cash flow (DCF) model is widely recognized as an appropriate model to utilize in arriving at a reasonable recommended return on equity that should be authorized for a utility. The concept underlying the DCF model is to determine the cost of common equity capital to the utility, which reflects the current economic and capital market environment. For example, a company may achieve a return on common equity that is higher than its cost of common equity. This situation will tend to increase the share price. However, this does not mean that this past achieved return is the barometer for what would be a fair authorized return in the context of a rate case. It is the lower cost of capital that should be recognized as a fair authorized return. If a utility continues to be allowed a return on common equity that is not reflective of today's current low-cost-of-capital environment, then this will result in the possibility of excessive returns.

The authorized return should provide a fair and reasonable return to the investors of the company, while ensuring that ratepayers do not support excessive earnings that could result from the utility's monopolistic powers. However, this fair and reasonable rate does not necessarily guarantee revenues or the continued financial integrity of the utility.

It should be noted that a reasonable return may vary over time as economic conditions, such as the level of interest rates, and business conditions change. Therefore, the past, present and projected economic and business conditions must be analyzed in order to calculate a fair and reasonable rate of return.

One of the most commonly accepted indicators of economic conditions is the discount rate set by the Federal Reserve Board (Federal Reserve or Fed). The Federal Reserve tries to achieve its monetary policy objectives by controlling the discount rate (the interest rate charged by the Federal Reserve for loans of reserves to depository institutions) and the Federal (Fed) Funds Rate (the overnight lending rate between banks). However, recently the Fed Funds Rate has become the primary means for the Federal Reserve to achieve its monetary policy, and the discount rate has become more of a symbolic interest rate. This explains why the Federal Reserve's decisions now focus on the Fed Funds rate and this is reflected in the discussion of interest rates. It should also be noted that on January 9, 2003, the Federal Reserve changed the administration of the discount window. Under the changed administration of the discount window an eligible institution does not need to exhaust other sources of funds before coming to the discount window, nor are there restrictions on the purposes for which the borrower can use primary credit. This explains why the discount rate jumped from 0.75 percent to 2.25 percent on January 9, 2003, when the Fed Funds rate didn't change. Therefore, discount rates before January 9, 2003, are not comparable to discount rates after January 9, 2003.

At the end of 1982, the U.S. economy was in the early stages of an economic expansion, following the longest post-World War II recession. This economic expansion began when the Federal Reserve reduced the discount rate seven times in the second half of 1982 in an attempt to stimulate the economy. This reduction in the discount rate led to a reduction in the prime interest rate (the rate charged by banks on short-term loans to borrowers with high credit ratings) from 16.50 percent in June 1982, to 11.50 percent in

December 1982. The economic expansion continued for approximately eight years until July 1990, when the economy entered into a recession.

In December 1990, the Federal Reserve responded to the slumping economy by lowering the discount rate to 6.50 percent (see Schedules 2-1 and 2-2). Over the next year-and-a-half, the Federal Reserve lowered the discount rate another six times to a low of 3.00 percent, which had the effect of lowering the prime interest rate to 6.00 percent (see Schedules 3-1 and 3-2).

In 1993, perhaps the most important factor for the U.S. economy was the passage of the North American Free Trade Agreement (NAFTA). NAFTA created a free trade zone consisting of the United States, Canada and Mexico. The rate of economic growth for the fourth quarter of 1993 was one the Federal Reserve believed could not be sustained without experiencing higher inflation. In the first quarter of 1994, the Federal Reserve took steps to try to restrict the economy by increasing interest rates. As a result, on March 24, 1994, the prime interest rate increased to 6.25 percent. On April 18, 1994, the Federal Reserve announced its intention to raise its targeted interest rates, which resulted in the prime interest rate increasing to 6.75 percent. The Federal Reserve took action again on May 17, 1994, by raising the discount rate to 3.50 percent. The Federal Reserve took three additional restrictive monetary actions, with the last occurring on February 1, 1995. These actions raised the discount rate to 5.25 percent, and in turn, banks raised the prime interest rate to 9.00 percent.

The Federal Reserve then reversed its policy in late 1995 by lowering its target for the Fed Funds Rate by 0.25 percentage points on two different occasions. This had the effect of lowering the prime interest rate to 8.50 percent. On January 31, 1996, the Federal Reserve lowered the discount rate to a rate of 5.00 percent.

The actions of the Federal Reserve from 1996 through 2000 were primarily focused on keeping the level of inflation under control, and it was successful. The inflation rate, as measured by the *Consumer Price Index - All Urban Consumers* (CPI), had never been higher than 3.70 percent during this period. The increase in CPI stood at 4.10 percent for the twelve months ending December 31, 2007 (see attached Schedules 4-1, 4-2 and 6). The unemployment rate was 5.00 percent as of December 2007.

The combination of low inflation and low unemployment had led to a prosperous economy from 1993 through 2000 as evidenced by the fact that real gross domestic product (GDP) of the United States increased every quarter during this period. However, GDP actually declined for the first three quarters of 2001, indicating there was a contraction in the economy during these three quarters. This contraction of GDP for more than two quarters in a row meets the textbook definition of a recession. According to the National Bureau of Economic Research, the recession began in March of 2001 and ended eight months later. Since the recession ended, GDP had been low up until the second quarter of 2003, but since the second quarter of 2003, GDP has been fairly healthy. GDP grew at a rate of 4.90 percent for the third quarter of 2007 (see attached Schedule 6).

The Value Line Investment Survey: Selection & Opinion, November 23, 2007, estimates inflation to be 3.90 percent for 2007, 2.00 percent for 2008 and 2.30 percent for 2009. The Congressional Budget Office, *The Budget and Economic Outlook: Fiscal Years 2008-2017,* issued January 2008, states that inflation is expected to be 2.8 percent for 2007, 2.90 percent for 2008 and 2.30 percent for 2009 (see attached Schedule 6).

Short-term interest rates, those measured by three-month U.S. Treasury Bills, are estimated to be 4.50 percent in 2007, 3.30 percent in 2008 and 4.70 percent in 2009 according to Value Line's predictions. Value Line expects the long-term Thirty-Year U.S. Treasury Bonds to average 4.80 percent in 2007, 4.70 percent in 2008 and 5.20 percent in 2009. The current rate for three-month U.S. Treasury Bills was 3.00 percent as of December 1, 2007, as noted on the St. Louis Federal Reserve website, http://research.stlouisfed.org/fred2/series/TB3MS/22. The current rate for Thirty-Year U.S. Treasury Bonds was 4.28 percent as of January 28, 2008, as noted on the CBS MarketWatch website, http://www.marketwatch.com.

GDP is a benchmark utilized by the Commerce Department to measure economic growth within the U.S. borders. Real GDP is measured by the actual GDP, adjusted for inflation. Value Line stated that real GDP growth is expected to increase by 2.10 percent in 2007, 2.00 percent in 2008 and 3.00 percent in 2009. The Congressional Budget Office, *The Budget and Economic Outlook: Fiscal Years 2008-2018*, stated that real GDP is expected to increase by 2.20 percent in 2007, 1.70 percent in 2008 and 2.80 percent in 2009 (see attached Schedule 6).

In summary, when combining the previously mentioned sources, inflation is expected to be in the range of 2.0 to 2.9 percent, increase in real GDP in the range of 1.7 to 3.0 percent and long-term interest rates are expected to range from 4.7 to 5.2 percent.

Selected excerpts from *The Value Line Investment Survey: Selection & Opinion,* February 8, 2008, follow:

> **The Federal Reserve is trying to rescue a slumbering economy,** and is doing so by aggressively reducing interest rates. In fact, the Fed has now cut borrowing costs five times since last summer when it began the monetary easing process, with the two latest moves (of three-quarters of a percentage point and one-half a point) coming on January 22nd and January 30th, respectively. Fed policy makers now have reduced the federal funds rate (the overnight lending rate between banks) from 5.25% to 3.00% in those five steps. Financial market turmoil, the housing downturn, and fears of a broadening business slump are contributing to the Fed's recently more-aggressive monetary stance.
>
> **We think the Fed is on the right track.** To be sure, the succession of rate reductions—which are designed to breathe life back into a **softening** economy—will take several months to begin working. That caveat aside, the Fed needed to start the rate-lowering process when it did last summer. In fact, one can argue that the Fed may have been a bit too slow in reacting to the steady flow of weak data from a number of key consumer markets.
>
> **Staving off a recession will be a challenge,** given the serious turmoil in the housing and financial sectors. Indeed, based on the overall trends in place now, even the lackluster 0.6% rate of gross domestic product growth posted in last year's final period may not be matched in the current quarter. In fact, no growth—or even a slight decline in GDP—would not be all that surprising. Thereafter, the recent rate cuts and hoped-for tax relief (as part of a government stimulus package) might help engineer a mild upturn in business activity by late in the second quarter. However, we think that there is at least a one in two chance of a recession this year. (A recession is defined as two consecutive quarters of declining GDP.)

Meanwhile, earnings are tracking **an uneven path,** with the financial and homebuilding companies doing very poorly, but with strength in some high profile technology names, such as *Microsoft*, being partly offsetting.

Investors are understandably on edge. Reflecting this fact, equities are materially lower so far this year, a few sharp rallies notwithstanding.

Conclusion: With interest rates probably headed lower, the case for buying equities is now strengthening. Please refer to the inside back cover of *Selection & Opinion* for our Asset Allocation Model's current reading.

The DCF model is a market-oriented approach for deriving the cost of common equity. The cost of common equity calculated from the DCF model is inherently capable of attracting capital. This results from the theory that security prices adjust continually over time, so that an equilibrium price exists and the stock is neither undervalued nor overvalued. It can also be stated that stock prices continually fluctuate to reflect the required and expected return for the investor.

The constant-growth form of the DCF model was used in this analysis. This model relies upon the fact that a company's common stock price is dependent upon the expected cash dividends and upon cash flows received through capital gains or losses that result from stock price changes. The interest rate which discounts the sum of the future expected cash flows to the current market price of the common stock is the calculated cost of common equity. This can be expressed algebraically as:

$$\text{Present Price} = \begin{array}{c}\text{Expected Dividends}\\ \text{Discounted by k}\end{array} + \begin{array}{c}\text{Expected Price in 1 year}\\ \text{Discounted by k}\end{array} \qquad (1)$$

where k equals the cost of equity. Since the expected price of a stock in one year is equal to the present price multiplied by one plus the growth rate, equation (1) can be restated as:

$$\text{Present Price} = \frac{\text{Expected Dividends}}{(1+k)} + \frac{\text{Present Price }(1+g)}{(1+k)} \qquad (2)$$

where g equals the growth rate and k equals the cost of equity. Letting the present price equal P_0 and expected dividends equal D_1, the equation appears as:

$$P_0 = \frac{D_1}{(1+k)} + \frac{P_0(1+g)}{(1+k)} \qquad (3)$$

The cost of equity equation may also be algebraically represented as:

$$k = \frac{D_1}{P_0} + g \qquad (4)$$

Thus, the cost of common stock equity, k, is equal to the expected dividend yield (D_1/P_0) plus the expected growth in dividends (g) continuously summed into the future. The growth in dividends and implied growth in earnings will be reflected in the current price. Therefore, this model also recognizes the potential of capital gains or losses associated with owning a share of common stock.

The discounted cash flow method is a continuous stock valuation model. The DCF theory is based on the following assumptions:

1. Market equilibrium;
2. Perpetual life of the company;
3. Constant payout ratio;
4. Payout of less than 100% earnings;
5. Constant price/earnings ratio;
6. Constant growth in cash dividends;
7. Stability in interest rates over time;
8. Stability in required rates of return over time; and
9. Stability in earned returns over time.

Flowing from these, it is further assumed that an investor's growth horizon is unlimited and that earnings, book values and market prices grow hand-in-hand. Although the entire list of the above assumptions is rarely met, the DCF model is a reasonable working model describing an actual investor's expectations and resulting behaviors.

The CAPM describes the relationship between a security's investment risk and its market rate of return. This relationship identifies the rate of return which investors expect a security to earn so that its market return is comparable with the market returns earned by other securities that have similar risk. The general form of the CAPM is as follows:

$$k = R_f + \beta\,(R_m - R_f)$$

where:

k	=	the expected return on equity for a specific security;
R_f	=	the risk-free rate;
β	=	beta; and
$R_m - R_f$	=	the market risk premium.

The first term of the CAPM is the risk-free rate (R_f). The risk-free rate reflects the level of return that can be achieved without accepting any risk. In reality, there is no such risk-free asset, but it is generally represented by U.S. Treasury securities.

The second term of the CAPM is beta (β). Beta is an indicator of a security's investment risk. It represents the relative movement and relative risk between a particular security and the market as a whole (where beta for the market equals 1.00). Securities with betas greater than 1.00 exhibit greater volatility than do securities with betas less than 1.00. This causes a higher beta security to be less desirable to a risk-averse investor and therefore requires a higher return in order to attract investor capital away from a lower beta security.

The final term of the CAPM is the market risk premium ($R_m - R_f$). The market risk premium represents the expected return from holding the entire market portfolio less the expected return from holding a risk-free investment.

Combustion Turbine Unit In-Service Test Criteria (Nameplate Capacity of ≥ 95 MW)

Riverton 12

1. All major construction work is complete.

   Based on personal observations of the facility on February 7, 2007; all major construction is completed.

2. All preoperational tests have been successfully completed.

   Based on review of testing records, preoperational testing was completed by February 2007 to support operational testing.

3. Unit successfully meets all contract operational guarantees.

   Based on review of testing records, operational testing performed in February, March, and April 2007 satisfied all contract operational guarantees.

4. Unit successfully demonstrates its ability to initiate the proper start sequence resulting in the unit operating from zero (0) rpm (or turning gear) to full load when prompted at a location (or locations) from which it is normally operated.

   Based on review of computer tabular data for operation of the unit on February 19, 2007, the unit successfully demonstrated proper start sequence from zero (0) speed to full load when prompted by the operator.

5. If unit has fast start capability, the unit demonstrates its ability to meet the fast start capability.

   Not applicable to this unit.

6. Unit successfully demonstrates its ability to initiate the proper shutdown sequence from full load resulting in zero (0) rpm (or turning gear) when prompted at a location (or locations) from which it is normally operated.

   Based on review of computer tabular data for operation of the unit on March 14, 2007, the unit successfully demonstrated proper shutdown sequence from full load to zero (0) speed when prompted by the operator.

7. Unit successfully demonstrates its ability to operate at minimum load for one (1) hour.

   Based on review of computer tabular data for operation on February 19, 2007, the units operated successfully at minimum load for greater than one (1) hour.

8. Unit successfully demonstrates its ability to operate at or above 95% of nominal capacity for four (4) continuous hours.

   Based on review of computer tabular data for operation on February 14, 2007, the unit operated successfully at or above 95% of nominal capacity for greater than four (4) continuous hours.

9. Unit successfully demonstrates its ability to produce an amount of energy (MWh) within a 72 hour period that results in a capacity factor of at least 50% during the period when calculated by the formula: capacity factor = (MWh generated in 72 hours) / (nominal capacity x 72 hours).

   Based on review of computer tabular data for operation on February 14 and 15, 2007, the unit successfully demonstrated its ability to achieve a capacity factor in excess of 50% within a 72 hour period.

10. Sufficient transmission interconnection facilities shall exist for the total plant design net electrical capacity at the time the unit is declared fully operational and used for service.

    Based on review of Southwest Power Pool (SPP) "Facility Study for Generation Interconnection Request GEN-2004-017" and EDE line relay test reports for the completed Riverton 12 interconnection, the generating unit is capable of connecting its design net electrical capacity to the transmission system. Additionally, the generating unit has been operated and connected to the transmission system at numerous times during testing activities and subsequent to the test activities.

11. Sufficient transmission facilities shall exist for the total plant design net electrical capacity from the generating station into the utility service territory at the time the unit is declared fully operational and used for service.

    Based on review of SPP "System Facilities Study for the Designation of a New Network Resource, #SPP-2003-253-2" (which determined transmission network upgrades related to the installation of Riverton 12) and a summary of transmission network upgrades completed by EDE, the generating unit is capable of delivering its design net electrical capacity into the utility service territory.

12. If unit has dual fuel capability, the unit successfully demonstrates its ability to start on the back up/secondary fuel as described in Item No. 4.

    Not applicable to this unit.

13. If unit has dual fuel capability, the unit successfully demonstrates its ability to transfer between the two fuels while on line.

    Not applicable to this unit.

THE EMPIRE DISTRICT ELECTRIC COMPANY - CASE NO. ER-2008-0093 SUMMARY OF ANNUALIZED AND NORMALIZED RATE REVENUE								
Rate Schedule	**As Recorded Billed Perm Rate+ IEC TY $**	**Revised As Billed Perm Rate+ IEC TY $**	**Annualize for Rate Switch**	**Annualize for 1/1/2007 Rate Change**	**Normalize for Weather**	**365-Days Adjust.**	**Customer Growth**	**Total Normalized Revenue**
RG-Residential	$141,218,524	$141,218,524	$0	$7,990,248	($2,519,714)	($428,888)	$2,435,915	$148,696,085
CB-Commercial	$30,782,991	$30,782,991	($505,364)	$1,724,574	($425,929)	$12,898	$577,084	$32,166,253
SH-Small Heating	$7,879,643	$7,879,643	$0	$457,520	($76,998)	($8,842)	$200,453	$8,451,776
PFM-Feed Mill/Grain Elev	$64,867	$64,867	$0	$4,024	$0	$0	$0	$68,891
MS-Traffic Signals	$62,608	$62,608	$0	$3,032	$0	$0	$0	$65,640
GP-General Power	$57,971,763	$57,971,763	$313,575	$3,163,139	($436,421)	$231,802	$1,176,421	$62,420,278
TEB-Total Electric Bldg	$24,817,719	$24,817,719	$0	$1,434,186	($212,164)	$20,467	$733,437	$26,793,646
LP-Large Power	$39,644,926	$39,722,798	$184,624	$1,620,559	$0	($81,686)	$0	$41,446,295
SC-P PRAXAIR Transmission	$2,357,368	$2,763,592	$0	$138,457	$0	$0	$0	$2,902,049
SPL-Municipal St Lighting	$1,370,013	$1,370,013	$0	$68,216	$0	$0	$0	$1,438,229
PL-Private Lighting	$3,557,128	$3,557,128	$0	$179,756	$0	$0	$0	$3,736,884
LS-Special Lighting	$146,377	$146,377	$0	$7,476	$0	$0	$0	$153,853
CP-Cogeneration Purchase	($698)	($698)	$0	$0	$0	$0	$0	($698)
Subtotal	$309,873,228	$310,357,324	($7,165)	$16,791,187	($3,671,225)	($254,249)	$5,123,310	$328,339,181
Other Rate Revenue								
Excess Facilities Charges	$1,800,072	$1,837,080		$45,319				$1,882,398
Unaccounted for	($6,654)	($6,654)						($6,654)
Interruptible Credits		($342,912)						($342,912)
Special Discounts		($134,829)		$134,829				$0
Total MO Billed Rate Rev	$311,666,646	$311,710,009	($7,165)	$16,971,335	($3,671,225)	($254,249)	$5,123,310	$329,872,014

Appendix 4

THE EMPIRE DISTRICT ELECTRIC COMPANY
ER-2008-0093

Account Number	Description	ASL Years	Net Salvage %	Ordered Depreciation Rate %
	STEAM PRODUCTION PLANT			
	RIVERTON			
311.00	Structures and Improvements	95.0	(0.10)	1.05
312.00	Boiler Plant Equipment	54.0	(0.30)	1.86
314.00	Turbogenerator Units	63.0	(0.27)	1.59
315.00	Accessory Electric Equipment	56.0	(0.09)	1.79
316.00	Miscellaneous Power Plant Equipment	51.0	0.10	1.96
	ASBURY			
311.00	Structures and Improvements	95.0	(0.40)	1.06
312.00	Boiler Plant Equipment	54.0	(1.18)	1.87
312.70	Unit Train	15.0	0.00	6.67
314.00	Turbogenerator Units	63.0	(1.06)	1.60
315.00	Accessory Electric Equipment	56.0	(0.36)	1.79
316.00	Miscellaneous Power Plant Equipment	51.0	0.39	1.95
	IATAN			
311.00	Structures and Improvements	95.0	(0.69)	1.06
312.00	Boiler Plant Equipment	54.0	(2.02)	1.89
314.00	Turbogenerator Units	63.0	(1.84)	1.62
315.00	Accessory Electric Equipment	56.0	(1.62)	1.81
316.00	Miscellaneous Power Plant Equipment	51.0	0.67	1.95
	HYDRAULIC PRODUCTION PLANT			
	OZARK BEACH			
331.00	Structures and Improvements	61.0	(1.14)	1.66
332.00	Reservoirs, Dams and Waterways	60.0	0.00	1.67
333.00	Waterwheels, Turbines and Generators	68.0	0.00	1.47
334.00	Accessory Electric Equipment	70.0	(1.14)	1.44
335.00	Miscellaneous Power Plant Equipment	41.0	0.00	2.44
	OTHER PRODUCTION PLANT			
	RIVERTON CT			
341.00	Structures and Improvements	55.0	0.00	1.82
342.00	Fuel Holders, Producers and Access.	26.0	0.00	3.85
343.00	Prime Movers	52.0	(0.05)	1.92
344.00	Generators	55.0	0.00	1.82
345.00	Accessory Electric Equipment	28.0	0.00	3.57
346.00	Miscellaneous Power Plant Equipment	25.0	0.04	4.00
	ENERGY CENTER CT			
341.00	Structures and Improvements	55.0	0.00	1.82
342.00	Fuel Holders, Producers and Access.	26.0	0.00	3.85
343.00	Prime Movers	52.0	(0.06)	1.92
344.00	Generators	55.0	0.00	1.82
345.00	Accessory Electric Equipment	28.0	0.00	3.57
346.00	Miscellaneous Power Plant Equipment	25.0	0.06	4.00
	ENERGY CENTER JET ENGINES			
341.00	Structures and Improvements	55.0	0.00	1.82
344.00	Generators	55.0	0.00	1.82
345.00	Accessory Electric Equipment	28.0	0.00	3.57
346.00	Miscellaneous Power Plant Equipment	25.0	0.19	3.99

THE EMPIRE DISTRICT ELECTRIC COMPANY
ER-2008-0093

Account Number	Description	ASL Years	Net Salvage %	Ordered Depreciation Rate %
	STATE LINE CT			
341.00	Structures and Improvements	55.0	0.00	1.82
342.00	Fuel Holders, Producers and Access.	26.0	0.00	3.85
343.00	Prime Movers	52.0	(0.12)	1.93
344.00	Generators	55.0	0.00	1.82
345.00	Accessory Electric Equipment	28.0	0.00	3.57
346.00	Miscellaneous Power Plant Equipment	25.0	0.16	3.99
	STATE LINE CC			
341.00	Structures and Improvements	35.0	0.00	2.86
342.00	Fuel Holders, Producers and Access.	35.0	0.00	2.86
343.00	Prime Movers	35.0	(0.18)	2.86
344.00	Generators	35.0	0.00	2.86
345.00	Accessory Electric Equipment	35.0	0.00	2.86
346.00	Miscellaneous Power Plant Equipment	35.0	0.17	2.85
	TRANSMISSION PLANT			
352.00	Structures & Improvements	55.0	(15.00)	2.09
353.00	Station Equipment	50.0	(10.00)	2.20
354.00	Towers & Fixtures	65.0	(25.00)	1.92
355.00	Poles & Fixtures	60.0	(100.00)	3.33
356.00	Overhead Conductors	65.0	(40.00)	2.15
	DISTRIBUTION PLANT			
361.00	Structures & Improvements	60.0	(25.00)	2.08
362.00	Station Equipment	45.0	15.00	1.89
364.00	Poles, Towers & Fixtures	46.0	(100.00)	4.35
365.00	Overhead Conductors	53.0	(100.00)	3.77
366.00	Underground Conduit	37.0	(45.00)	3.92
367.00	Underground Conductors	32.0	(15.00)	3.59
368.00	Transformers	45.0	(25.00)	2.78
369.00	Services	40.0	(100.00)	5.00
370.00	Meters	44.0	0.00	2.27
371.00	Meter Installations	25.0	(45.00)	5.80
373.00	Street Lighting	48.0	(50.00)	3.13
	GENERAL PLANT			
390.00	Structures & Improvements	40.0	(10.00)	2.75
391.10	Office Furniture and Equipment	20.0	0.00	5.00
391.20	Computer Equipment	10.0	0.00	10.00
392.00	Transportation Equipment	12.0	15.00	7.08
393.00	Stores Equipment	30.0	5.00	3.17
394.00	Tools, Shop & Garage Equipment	20.0	10.00	4.50
395.00	Laboratory Equipment	38.0	0.00	2.63
396.00	Power Operated Equipment	15.0	5.00	6.33
397.00	Communication Equipment	25.0	0.00	4.00
398.00	Miscellaneous Equipment	22.0	0.00	4.55

1 Calculation of Amortization to meet Financial Ratio Targets 2/22/2008

2 Case No. ER-2008-0093, Empire District Electric

Line	Item	Source	Total Company	Juris Alloc
5	Additional Net Balance Sheet Investment			130,710,000
6	Rate Base	Staff Acct. Schedule 2 *		670,433,470
7	Jurisdictional Allocation for Capital			0.837404
9	Total Capital	L5+L6		801,143,470
10	Equity	Barnes Workpapers	0.5082	407,141,111
11	Trust Preferred	Barnes Workpapers	0.0458	36,692,37[illegible]
12	Long-term Debt	Barnes Workpapers	0.4461	357,390,102
13	Cost of Debt	Barnes Workpapers		6.80%
14	Interest Expense	L12 * L13 (+$2,125,000 (TOPRs))		26,427,527
16	Electric Sales Revenue	Staff Acct. Schedule 9, L.1-2, + Rate Increase		353,642,502
17	Other Electric Operating Revenue	Staff Acct. Schedule 9, L.3		3,010,138
18	Water Revenue			
19	Operating Revenue	L16 + L17		356,652,640
21	Operating and Maintenance Expense	Staff Acct. Schedule 9, L.95 (less cust. deposits)		217,470,936
22	Depreciation	Staff Acct. Schedule 9, L.98		35,721,512
23	Amortization	Staff Acct. Schedule 9, L.100		13,504,374
24	Interest on Customer Deposits	Staff Acct. Schedule 10, Adj. S-82.1		593,870
25	Taxes Other than Income Taxes	Staff Acct. Schedule 9, L.102		13,106,455
26	Federal and State Income Taxes	Staff Acct. Schedule 9, L.113 (plus rate incr. impact)		19,201,605
27	Gains on Disposition of Plant			
28	Total Water Operating Expenses			
29	Total Electric/Water Operating Exp	Sum of L. 21-28		299,598,752
31	Operating Income - Electric	L19 - L29		57,053,888
32	Operating Income - Water			
33	less: Interest Expense	L14		-26,427,527
34	Depreciation	L22		35,721,512
35	Amortization			13,504,374
36	Deferred Taxes	Staff Acct. Schedule 9, L112		-3,309,636
37	Funds from Operations (FFO)	Sum of L31-36		76,542,611
43	Additional Financial Information Needed for Calculation of Ratios			
44	Capitalized Lease Obligations	EDE Accounts 227 + 243	479,951	401,913
45	Short-term Debt Balance	EDE Form 10-Q, p. 8	33,040,000	27,667,828
46	Short-term Debt Interest	EDE Accounts 417.891 + 431.400	2,940,317	2,462,233
47	Cash Interest Paid	Information Supplied by EDE	31,049,437	26,000,923
48	AFUDC Debt (capitalized interest)	EDE Form 10-Q, p. 4	550,469	460,965
50	Adjustments Made by Rating Agencies for Off-Balance Sheet Obligations			
51	Debt Adj for Off-Balance Sheet Obligs			
52	Operating Lease Debt Equivalent	Information Supplied by EDE	2,937,000	2,459,456
53	Purchase Power Debt Equivalent	Information Supplied by EDE	86,546,000	72,473,967
54	Total OSB Debt Adjustment	L52 + l53	89,483,000	74,933,422
56	Operating Lease Deprec Adjustment	Information Supplied by EDE	1,255,000	1,050,942
58	Interest Adjustments for Off-Balance Sheet Obligations			
59	Present Value of Operating Leases	L52 * 10%	293,700	245,946
60	Purchase Power Debt Equivalent	L53 * 10%	8,654,600	7,247,397
61	Total OSB Interest Adjustment	L59 + L60	8,948,300	7,493,342

62			
63	Ratio Calculations		
64	Adjusted Interest Expense	L14 + L46 + L61	36,383,102
65	Adjusted Total Debt 6/30/06	(L11/2) + L12 + L44 + L45 +L54	478,739,451
66	Adjusted Total Debt 6/30/05	Same as L65, but for prior year	443,934,000
67	Adjusted Total Capital	L9 + L44 + L45 + L54	904,146,633
68			
69	Adj. FFO Interest Coverage	(L37 + L47 + L48 + L61)/(L14 + L48 + L61)	3.21
70	Adj. FFO as a % of Average Total Debt	(L37 + L56)/(avg. of L65 + L66)	0.1682
71	Adj. Total Debt to Total Capital	L65/L67	0.5295
72			
73	Changes Required to Meet Ratio Targets		
74	Adj. FFO Interest Coverage Target		3.20
75	FFO Adjustment to Meet Target	(L74 - L69) * L64	-503,677
76	Interest Adjustment to Meet Target	L37 * (1/L74 - 1) - 1/L69 - 1)	217,563
77			
78	Adj. FFO as a % of Average Total Debt		0.195
79	FFO Adjustment to Meet Target	(L78 - L70) * (Avg of L65 + L66)	12,367,108
80	Debt Adjustment to Meet Target	L37 * (1/L78 - 1/L70)	-62,562,082
81			
82	Adj. Total Debt to Total Capital Target		56.50%
83	Debt Adjustment to Meet Target	(L82 - L71) * L67	32,103,397
84	Total Capital Adjustment to Meet Target	L65/L82 - L67	-56,820,172
85			
86	Amortization and Revenue Needed to Meet Targeted Ratios		
87	FFO Adj Needed to Meet Target Ratios	Maximum of L75, L79 or zero	12,367,108
88	Effective Income Tax Rate		0.3839
89	Deferred Income Taxes	L87 * L88/(1 - L88)	-7,706,107
90	Total Amortization Req for FFO Adj	L87 - L89	20,073,215
91			
92	* All references to Staff Acct. Schedules tie to schedules supporting amounts reflected in the		
93	Accounting Schedules filed 2/22/08		