MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

COST OF SERVICE

Great Plains Energy, Incorporated
KANSAS CITY POWER & LIGHT COMPANY

CASE NO. ER-2009-0089

Test Year 2007
Updated through September 30, 2008
With True-up as of March 31, 2009

Jefferson City, Missouri
February 11, 2009

** **Denotes Highly Confidential Information** **

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COST OF SERVICE REPORT

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I. Background of Great Plains Energy and Kansas City Power & Light Company

Kansas City Power & Light Company ("KCPL" or "the Company") is a corporation duly organized and existing under the laws of the State of Missouri. KCPL is a regulated public utility operating in the states of Kansas and Missouri. It provides wholesale electricity to several municipal customers under the jurisdiction of the Federal Energy Regulatory Commission. KCPL distributes and sells electric service to the public in its certificated areas in Kansas and Missouri, and is an "electrical corporation" and "public utility" subject to the jurisdiction, supervision, and control of the Commission under Chapters 386 and 393 of the Revised Statutes of Missouri. KCPL is wholly owned by Great Plains Energy ("GPE") and an affiliate of KCP&L Greater Missouri Operations Company ("GMO." which was formerly known as Aquila, Inc. and before that UtiliCorp United, Inc.). GPE is a public utility holding company regulated under the Public Utility Holding Company Act of 2005, which was enacted as part of the Energy Policy Act of 2005. As a holding company, GPE does not provide electric service to retail customers.

On July 28, 2005, the Commission approved KCPL's Regulatory Plan in Case No. EO-2005-0329 which contemplated a series of up to four rate case filings designed to address the economic impacts of KCPL's planned major environmental upgrades to LaCyne 1 and Iatan 1 and the new construction of Iatan 2. This plan also included a commitment to invest in wind energy which KCPL did in September 2006 with the in-service of the Spearville Wind Farm. The current case is the third such rate case filing and the 2nd of two optional rate filings. The first rate case filed on February 1, 2006 (ER-2006-0314) was required by the Regulatory

Plan and the fourth and last rate case is required and will be filed timed to allow the in-service of the Iatan 2 Generating Station, currently expected to go into service summer or fall of 2010.

On April 4, 2007, GPE, KCPL, and Aquila, Inc. ("Aquila"), filed a joint application with the Missouri Public Service Commission ("the PSC" or "the Commission"), designated as Case No. EM-2007-0374 requesting a series of transactions which ultimately would result in GPE acquiring Aquila's Missouri electric and steam operations, as well as its merchant services operations. These merchant services operations primarily consisted of a 340 megawatt generating facility located in Mississippi, ("Crossroads"), and certain residual natural gas contracts. The Commission approved the request of GPE, KCPL, and Aquila, Inc., in an Order effective July 1, 2008. Some time after GPE acquired it, Aquila changed its name to KCPL Greater Missouri Operations Company ("GMO").

II. Executive Summary

Please summarize the Staff's filing.

Curt Wells, of the Commission's Utility Operations Division, and I sponsor Staff's Cost of Service Report in this proceeding that is being filed concurrently with this testimony and the testimony of Mr. Wells. Staff's Cost of Service Report supports Staff recommendation regarding the amount of the rate increase that Staff expects will be needed in this case.

I present an overview of the results of Staff's review into the general rate increase request made by KCPL on September 5, 2008. Several members of the Commission Staff conducted Staff's review by examining all relevant and material components making up the revenue requirement calculation. These components can be broadly defined as capital structure and return on investment, rate base investment and income statement results including revenues, operating and maintenance expenses, depreciation expense, and related taxes, including income taxes. I provide an overview of the Staff's work on each.

Staff recommends that KCPL be permitted to increase its electric rates to recover an additional $45 million per year. This amount includes a substantial amount for an allowance for known and measurable changes that is expected to occur as result of the true-up in this case.

Major plant additions are expected to be completed in the first quarter of 2009 which will result in higher plant investment requiring increases in return, depreciation expenses and operating costs. Other plant additions will be added through the time of the true-up in this case causing costs to increase. Other cost increases will likely include payroll, payroll related benefits such as pensions and medical costs. Maintenance costs are expected to go up for the Commission's new rules on vegetation management and infrastructure inspection and repairs of the distribution and transmission system.

Staff examined the area of additional amortizations based on the Regulatory Plan relating to KCPL's Comprehensive Energy Plan the Commission approved in Case No. EO-2005-0329.

The following represent a non-exhaustive list of areas that make up Staff's filing:

- Rate of Return proposed by Staff
- Additional Amortizations authorized from the Regulatory Plan in Case No. EO-2005-0329
- Plant upgrades for environmental costs for Iatan 1 through the allowance for known changes
- Fuel costs and purchased power costs
- Off-system sales in the firm and non-firm bulk power markets
- Costs relating to the Commission's new rules on vegetation management and infrastructure inspection and repairs through the allowance for know changes
- Pension costs

- Jurisdictional Allocations
- Acquisition savings and transition costs

III. Kansas City Power and Light Company's Rate Case Filing

KCPL filed its rate case on September 5, 2008 reflecting an increase in Missouri retail rates of $101.5 million. This request represents a proposed 17.5% increase. The Commission designated this rate case as Case No. ER-2009-0089. KCPL's proposes a rate of return on equity of 10.75% applied to the 53.82% equity capital structure for GPE.

GMO also filed rate cases on September 5, 2008, for both its electric and steam operations. These cases have been designated as Case Nos. ER-2009-0090 and HR-2009-0092. GMO has different rates in two different areas – one in and about Kansas City, which was formerly served under the d/b/a Aquila Networks - MPS and one about St. Joseph, Missouri, which was formerly served under the d/b/a Aquila Networks – L&P. For ease, the areas with differing rates are referenced as "MPS and L&P" in this report. For MPS, GMO is requesting a rate increase in the amount of $66 million, representing a 14.4% increase. For L&P electric service, GMO is requesting an increase in the amount of $17.1 million, representing a 13.6% increase; and L&P steam service, GMO is requesting an increase in the amount of $1.3 million, representing a 7.7% increase.

A. Test Year

The test year being used in this case, as well as the GMO cases for MPS and L&P, is the 12-month period January 1, 2007, through December 31, 2007, updated for known and measurable changes through September 30, 2008, and trued-up through March 31, 2009.

IV. Rate of Return

A. Summary

The Financial Analysis Department Staff recommends that the Commission authorize an overall rate of return (ROR) of 7.73 percent to 8.24 percent for KCPL. Staff's rate of return recommendation is based on a recommended return on common equity (ROE) of 9.25 percent to 10.25 percent, midpoint 9.75 percent, applied to KCPL's September 30, 2008, common equity ratio of 50.65 percent. Staff's recommended ROE is driven by its comparable company analysis using a multiple-stage discounted cash flow (DCF) analysis. Staff continues to believe that the DCF methodology is the most reliable method available for estimating a utility company's cost of common equity. However, Staff decided to deviate from the constant-growth, single-stage DCF model (hereinafter referred to as the "constant-growth DCF") in this case because of current market conditions that appear to be causing analysts' earnings per share (EPS) growth rate estimates and stock prices to be inconsistent. A constant-growth DCF analysis using analysts' EPS growth rate estimates results in unreliable cost of equity estimates. If investors are fearful about the current recession and are concerned that the economy will continue to grow at a slow pace, then it is difficult to believe that investors would consider these analysts' estimated growth rates to be sustainable. For this reason, Staff deviated from its traditional reliance on the constant-growth DCF. In its CAPM analysis, Staff's use of historical earned risk premiums along with very low U.S. Treasury bond yields results in low estimated costs of common equity. Staff believes that its approach in this case attempts to make sense of the widely divergent results obtained from the constant-growth DCF using analysts' EPS growth rate estimates and the CAPM results using historical earned risk premiums and low treasury yields.

Staff's embedded cost of long-term debt recommendation of 6.203 percent is based on the cost of long-term debt outstanding at Great Plains Energy (GPE) and KCPL as of September 30, 2008. Staff accepted the embedded cost of debt estimate KCPL provided in response to Staff Data Request No. 111. Although KCP&L Greater Missouri Operations Company (GMO, formerly known as Aquila, Inc.) is also owned by GPE and is a part of the consolidated capital structure recommendation in this case, Staff chose not to include GMO's debt cost in its recommended ROR for KCPL because no new debt has been issued at either entity that may be commingled in the treasury.

Staff's capital structure recommendation is based on GPE's consolidated capital structure as of September 30, 2008. Schedule 8, contained within Appendix 2 attached to the Report, presents GPE's capital structure and associated capital ratios. KCPL's resulting ratemaking capital structure consists of 50.65 percent common stock equity, 0.76 percent preferred stock and 48.60 percent long-term debt.

Staff has prepared two attachments and 21 schedules that support its findings and recommendations in the cost of capital area. The attachments contain explanations of the DCF method and the CAPM. These attachments are denoted as Attachments A and B to this Report. The schedules present numerical support for Staff's rate of return recommendation, and are numbered as Schedules 1 through 21. Both attachments and 21 schedules can be found within Appendix 2 to this Report, with the attachments appearing first.

B. Legal Principles of Rate of Return

Rate of return witnesses are mindful of the constitutional parameters that guide the determination of a fair and reasonable rate of return. These parameters were announced by the United States Supreme Court in two seminal cases, *Bluefield Water Works and Improvement*

Company v. Public Service Commission of West Virginia (1923) (*Bluefield*) and *Federal Power Commission v. Hope Natural Gas Company* (1944) (*Hope*).[1]

The Supreme Court discussed the following main points in the *Bluefield* case:

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.[2]

In the *Hope* case the Court stated:

> 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

[1] ***Bluefield Water Works & Improv. Co. v. Pub. Serv. Comm'n of West Virginia,*** 262 U.S. 679, 43 S.Ct. 675, 67 L.Ed. 1176 (1923); ***Fed. Power Comm'n v. Hope Nat. Gas Co.,*** 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333 (1943).
[2] ***Bluefield,*** *supra,* 262 U.S. at 692-93, 43 S.Ct. at 679, 67 L.Ed. at 1182-1183.

> 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.[3]

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.

While the legal requirements announced in the *Hope* and *Bluefield* cases have not changed, it is important to recognize that the methodology used to estimate a reasonable rate of return has evolved considerably since these cases were decided over 60 years ago. In fact, two of the most commonly used models in making rate of return recommendations, the DCF model and the capital asset pricing model (CAPM), did not even become a part of mainstream finance until the 1960s. Likewise, capital markets are not confined to regional boundaries when determining the most efficient use of capital.

In mainstream finance literature, the DCF model, as used in utility ratemaking, is variously referred to as the dividend growth, Gordon growth and/or dividend discount model. This model was introduced by Myron J. Gordon for cost of common-equity determinations in 1962.[4] The use of this model for stock valuation purposes had been introduced before this time.

The basis for the CAPM was provided in 1964 by William F. Sharpe who received the Nobel Prize in 1990 for much of his work in producing this model.[5] The CAPM is frequently used by investment bankers to estimate the cost of capital for purposes of discounting future cash flows to determine an estimated present value of an enterprise.

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[3] ***Hope,*** *supra*, 320 U.S. at 603, 64 S.Ct. at 288, 88 L.Ed. at 345.
[4] Frank K. Reilly and Keith C. Brown, *Investment Analysis and Portfolio Management*, Fifth Edition, The Dryden Press, 1997, p. 438.
[5] Zvie Bodie, Alex Kane and Alan J. Marcus, *Essentials of Investments,* Richard D. Irwin, Inc. 1992, p. 11.

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 an earned 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.

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 guarantee any particular level of return to the utility's shareholders.

Although neither the DCF model nor the CAPM were used for making rate-of-return recommendations during the period in which the *Hope* and *Bluefield* decisions were made, state commissions (including the Missouri Commission) throughout the country have accepted these methodologies for purposes of estimating rates of return for utility ratemaking.

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 judge the fairness and reasonableness of a rate of return recommendation.

C. Economic Conditions

Because current economic conditions may impact the rate of return a utility needs to attract investors, it is important for the Commission to consider the past, current and projected capital and economic environment when determining a reasonable authorized ROE for KCPL. However, just as one should be cautious about relying too heavily on analyst earnings estimates, one should also use caution when evaluating projected economic conditions. It is most important to try and determine what investors expect when estimating the cost of capital, not necessarily what economists and analysts are projecting. This can be done by evaluating the capital market, the interest rate environment and historical patterns of demand growth.

The world and the U.S. economy are experiencing uncertain times. This makes the estimation of a fair and reasonable cost of capital even a tougher task than normal. Not only is the estimation of the cost of capital difficult, but determining what is reasonable and fair in our current recession is even more difficult. Staff will provide the Commission with what I believe to be the current cost of capital for an electric utility company of at least investment grade credit quality. The challenge in estimating the cost of capital in today's environment comes from the fact that although the risk premiums for certain investments have increased, the risk premium for much safer investments has decreased. There has been an increase in the spread between the cost of low risk securities compared to high risk securities. The Federal Reserve (Fed) has induced much of the lower cost of government securities, at least on the shorter end of the maturity spectrum.

On December 16, 2008, the Fed cut the Fed Funds Rate to between zero and 0.25 percent, which is even below the previous historic low of 1.00 percent under former Fed Chairman Alan Greenspan. This is clearly due to the Fed's concern about the current state of the U.S. economy and what may lie ahead. The Fed normally reserves such aggressive actions for times in which it is concerned about the possibility of a deflationary price environment due to a severe contraction in the economy. In fact, this was the Fed's concern when it reduced the Fed Funds Rate to 1.00 percent under Chairman Greenspan.

Although the current economic and capital market slump picked up considerable speed during the fall of 2008, the Fed began to react to concerns about the economy in the Fall of 2007 (the National Bureau of Economic Research declared in December 2008 that the U.S. has been in a recession since December 2007). Up until September 18, 2007, the Fed had held rates steady at 5.25 percent. However, in response to concerns about a tightening credit market, due in part to problems in the sub-prime market at the time, the Fed reduced the Fed Funds rate by a full 50 (0.50%) basis points on September 18, 2007. Over the remaining part of 2007, the Fed lowered the Fed Funds Rate by 25 basis point increments, on October 31, 2007, and December 11, 2007. The Fed continued to lower the Fed Funds rate through most of the winter and spring of 2008 until they left the rate at 2.25 percent after April 30, 2008. The Fed appeared to not want to lower the Fed Funds rate any further due to concerns about sparking inflation during a period in which certain commodity prices, such as gasoline, were sky-rocketing. However, then came the financial meltdown in which the Fed and the U.S. Treasury began to play a large role in orchestrating bailouts, mergers, acquisitions and allowing some financial institutions to go into bankruptcy, such as Lehman Brothers. The Fed continued to lower the Fed Funds rate by two 50-basis point increments on October 8, 2008, and October 29, 2008, before it made its last cut on December 16, 2008, to arrive at the current rate of zero to 0.25 percent.

According to a recent article in the *Wall Street Journal (WSJ)*[6], during its meeting on December 17, 2008, the Fed stated that "The Federal Reserve will employ all available tools to

[6] Jon Hilsenrath, "Fed Cuts Rates Near Zero to Battle Slump: Historic Move Boosts Stocks as Consumer Prices, Housing Starts Drop Sharply; Obama calls for Government Spending Program," *The Wall Street Journal*, December 17, 2008, p. A1 – A2.

promote the resumption of sustainable economic growth and to preserve price stability." The Fed also emphasized that it expected interest rates to remain "exceptionally" low for some time, which could help bring down longer-term interest rates. According to the *WSJ* article "The trouble for Fed officials is that while official borrowing rates are very low, interest rates for borrowers with even a modicum of risk remain far above levels of a few months ago, which is squeezing the economy." The impact has been even greater for companies that are of questionable credit quality. For example, according to the same *WSJ* article 'BB'-rated junk bonds were trading at more than "14 percentage points above comparable Treasury bonds; a crushing borrowing cost for many low-rated companies, compared with a spread of less than six percentage points before September."

Although the Fed tries to influence long-term capital costs through its adjustments to the Fed Funds rate, long-term capital costs do not always respond. Therefore, it is important to analyze the long-term interest rate environment and consider it when recommending a reasonable cost of common equity.

Long-term interest rates, as measured by Thirty-year Treasury Bonds (30-year T-bonds), have dropped to extremely low levels recently. As of January 2009, the 30-year T-bonds averaged 3.13 percent (see Schedule 4-2), which is coming off an all-time low in December 2008 of 2.87 percent. However, because of investors' concerns about the economy during the last quarter of 2008, the average utility bond yields increased to as high as 7.80 percent, as of November 2008. As a result, the spread between the utility bond yields and 30-year T-bond yields hit an historical high of 380 basis points in November 2008 (see Schedule 4-4). The wide spread in November was due in large part to higher average utility bond yields. The increase in utility bond yields to 7.80 percent represents an approximate 200 basis point increase in the yield on public utility bond yields since 2005. Of this 200 basis point increase, 120 basis points have occurred within the last two months, which illustrates the dramatic tightening of the credit market since October 2008. As is typical in many credit-tightening cycles, the spreads between higher quality debt and lower quality debt have increased. Whereas, during a more stable economic environment the spread between A-rated utilities and Baa-rated utilities is typically around 30 basis points, as of November 2008, this spread was 138 basis points. The spread tends to be even smaller when evaluating the difference between an Aa-rated utility and an A-rated utility. This spread is typically around 15 basis points. As of November 2008 this spread was 123 basis points. This results in a spread of 261 basis points between an Aa-rated utility and a Baa-rated utility. This represents a 480 percent increase over the spread in more stable economic times. Consequently, there is a significant capital cost associated with being a less creditworthy company than in more stable economic times.

Although Staff had not received the most recent edition of the Mergent Bond Record at the time of writing this testimony, Staff has reviewed information from Bloomberg and Value Line that indicates that utility bond yields have dropped from the high levels reached in October and November of 2008. According to Bloomberg data, the average 20, 25 and 30-year BBB bond yield was approximately seven percent in December 2008. According to the February 6, 2009 issue of the *Value Line Selection and Opinion*, the yield on BBB-rated utility bonds was 7.04 percent as of January 28, 2009. Based on the 30-year T-bond yield of 3.45 percent as of January 28, 2009, and the BBB utility bond yield of 7.04 percent as of the same day, the spot yield spread was 360 basis points, which is still high, but less than the last couple of months of 2008. Also, it should be noted that Staff does not recommend the use of spot yields making determinations on any specific rate of return adjustments. It is important to evaluate yields over a longer period for purposes of making a responsible rate of return recommendation.

Although the recent tightening of the credit markets has had varying effects on corporations depending on their industry and their specific financial circumstance, according to a January 13, 2009, article in the *WSJ* "Bonds a Bright Spot for Utilities in '08: *Debt Issuance Rose 34% as Investors Shunned Commercial Paper, Stocks,"* the utility industry was able to sell more bonds in 2008 than it had in years. Although these bond issuances occurred throughout the year, this news is still noteworthy because the credit markets had experienced some tightening as far back as the fall of 2007 as the subprime credit issues started to filter into the economy. According to this article, utilities with investment grade credit ratings sold $47 billion of corporate bonds in 2008 compared to $35 billion in 2007 and $26.5 billion in 2006. This compared to a decline in the overall bond market to $645 billion in 2008 from $987 billion in 2007. The article also recognizes that "many utilities were hurt as market valuations tumbled amid investor fears that demand for their services would decline and that they would have difficulties raising the large sums of money that they require, at least at affordable rates." As will be explained later in this section of Staff's Cost of Service Report, the decline in utility stock prices due to concerns about future demand is a fundamental principle in estimating the cost of common equity when performing a DCF analysis. One of the companies mentioned in this article, Progress Energy Inc., is a part of the proxy group Staff used to estimate the cost of common equity for KCPL in this case. On January 8, 2009, Progress Energy issued 10-year bonds at a coupon rate of 5.3 percent. Consequently, it appears that the cost of capital for utility companies is returning to levels prior to the credit crisis. Another issue mentioned in the article is that, although the spreads over U.S. Treasury's for recent utility bond issuances have been high, much of these high spreads can be attributed at least in part to the extremely low rates on U.S. Treasury bonds. Consequently, while utility bond risk premiums over U.S. Treasury bonds have increased, because yields on U.S. Treasury bonds have decreased dramatically, this doesn't necessarily mean that the overall cost of capital to utilities has increased that much.

Although changes in interest rates heavily influence the cost of debt and equity to utility companies, it is important to reflect on recent results of the major stock market indices. According to the January 16, 2009, issue of *The Value Line Investment Survey: Selection & Opinion*, for the fourth quarter of 2008 the Dow Jones Industrial Average (DJIA) declined 19.1 percent, the Standard & Poor's (S&P) 500 declined 22.6 percent, the NASDAQ Composite Index (NASDAQ) declined 24.3 percent, and the Dow Jones Utility Average (DJUA) declined 13.5 percent. According to the same publication, for the twelve months ended December 31, 2008, the DJIA declined 33.8 percent, the S&P 500 declined 38.5 percent, the NASDAQ composite declined 40.5 percent, and the DJUA declined 30.4 percent.

As can be seen from the above, stock indices have suffered major declines in the past quarter, and year. While an initial reaction to a significant decline in stock prices may be to assume that the cost of capital has significantly increased, one must also consider the reasons why stock prices have declined. It appears that investors are concerned about a global slowdown in the economy, which would impact the expected return an investor would receive from growth in stock prices. Therefore, the required return may now be more concentrated in the dividend yield investors expect to receive. Staff will discuss this in more detail later in its testimony when explaining its cost of common equity recommendation. Another thing to consider about the above stock market results is that while the DJUA had declined with the rest of the market in

2008, the DJUA had performed quite well over previous years. According to a January 9, 2009, BMO Capital Markets report, "Electric Utilities: 2008 in Review; Outlook for 2009," the DJUA returned 54.6% for the period 2003 through 2008 while the S&P 500 returned 2.7%, the DJIA returned 5.2% and the NASDAQ returned 18.1% for the same period. Consequently, utility stocks, as measured by the DJUA, had been significantly outperforming the rest of the market for the past five years.

Although the DJUA is one of the more widely published utility indexes, it should be used with caution for purposes of drawing inferences about possible trends in regulated utilities' cost of capital because many of the companies in the DJUA have non-regulated operations that at least contribute to their performance. In fact, the Edison Electric Institute (EEI) does not consider a majority of the companies in the DJUA to be "regulated utilities," which is one of the criteria Staff used to select its comparable companies in this case. However, three of Staff's comparable companies are included in the DJUA and are classified as "regulated utilities" by EEI. Regardless, Staff does not consider the DJUA as a good proxy group for KCPL. However, comparing utility index results to the rest of the stock market can provide insight on the value being placed on utility stocks in general.

Utility indices can also vary in their results. For example the Value Line Utilities Group, which is composed of "utility" companies followed by Value Line, decreased by 15.9 percent for the fourth quarter of 2008, compared to the 13.5 percent decrease for the DJUA. The Value Line Utilities Group decreased 32.7 percent for all of 2008 compared to the DJUA's decrease of 30.4 percent. The Value Line Utilities index contains companies ranging from water utility companies, such as American States Water Company, to diversified natural gas companies, such as Devon Energy Corporation. However, during 2008 it appears that the DJUA and the Value Line Utilities Index have performed similarly.

It is also worthwhile to review some economic indicators for purposes of evaluating the reasonableness of a rate of return recommendation in this case. Although a reasonable DCF analysis captures investors' expectations about future economic conditions, investors will review some of this information to arrive at their own conclusion about a fair price to pay for utility stocks in today's environment.

The Value Line Investment Survey: Selection & Opinion, November 21, 2008, estimates inflation to be 4.5 percent for 2008, 1.3 percent for 2009 and 2.5 percent for 2010. The Congressional Budget Office, *The Budget and Economic Outlook: Fiscal Years 2009-2019*, January 2009, indicates an inflation rate of 4.4 percent for 2008 and estimates inflation to be 0.5 percent for 2009 and 1.4 percent for 2010 (see Schedule 5).

Short-term interest rates, those measured by three-month U.S. Treasury Bills, are estimated to be 1.6 percent in 2008, 1.5 percent in 2009 and 2.7 percent in 2010 according to Value Line's predictions. Value Line expects long-term Treasury bond rates to average 4.4 percent in 2008, 4.2 percent in 2009 and 4.5 percent in 2010.

The most recent weekly rate for three-month U.S. Treasury Bills was 0.19 percent (see Schedule 5). The most recent weekly rate for long-term treasury bonds was 3.45 percent (see Schedule 5).

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 1.4 percent in 2008, decrease by 0.9 percent in 2009 and increase by 2.5 percent in 2010. The Congressional Budget

Office, *The Budget and Economic Outlook: Fiscal Years 2009-2019,* stated that real GDP increased 1.9 percent in 2008 and is expected to decline by 1.9 percent in 2009 and increase by 0.4 percent in 2010 (see Schedule 5).

The Value Line *Investment Survey: Selection & Opinion,* January 9, 2009, stated the following in its Economic and Stock Market Commentary:

> **The United States and other countries are caught in the grip of what will likely be a long and painful recession.** This nation's economic difficulties—which have been apparent in housing for more than a year and in other areas for a shorter span of time—worsened noticeably last quarter. That period, which ended with one of the poorest holiday shopping seasons on record, may have seen U.S. gross domestic product tumble by 5%, or so.
>
> **At least two more quarters of sharp economic reversals look to be ahead of us.** True, a contraction in business activity of such mammoth proportions, as we probably saw last quarter, may have been a one-time affair. However, even if the worst of the downturn is behind us—due to the unprecedented governmental steps taken in 2008 and the massive monetary infusions by the Federal Reserve—there would seem to be enough cumulative weakness around in housing, autos, retailing, and industrial activity to almost ensure that GDP will decline by 2% to 4% in the first half of 2009.
>
> **Any business recovery in 2009 may arrive late and be selective, in our view.** Our sense is that the fiscal and monetary moves undertaken last year and the prospective federal government recovery plans likely to be forthcoming will lessen the severity and duration of the recession in select areas, such as infrastructure building and possibly even housing. However, the hoped-for second-half recovery is a bit conjectural at this time. Indeed, even if all goes well, any second-half growth may be capped at 1% to 2%.
>
> **While there is some room for optimism on the economy,** likely further increases in joblessness and the prospective additional declines in home prices do not augur well for the improvement in consumer spending that is needed to revive the economy. A partial offset to the above is likely to be the gains in disposable income that should evolve from the recent declines in heating oil, gasoline,

> and food costs. Once other sectors of the economy start to stabilize, the lower inflation should provide some help to spending.
>
> **The investment picture remains muddled.** Equities are still range bound, reflecting the tough business outlook, on the one hand, and the possibility that last year's dismal stock market performance may have partially taken these hard times into account, on the other hand.
>
> **Conclusion:** We think this tug of war will ultimately be resolved in favor of the bulls, assuming the economy starts to stabilize during the first half of 2009. Please refer to the inside back cover of *Selection & Opinion* for our Asset Allocation Model's current reading.

Staff believes that the economic and capital market environment of the past few months reflects a change in investors' expectations, which may have caused a slight increase in the cost of capital to utilities, at least temporarily. While it will be apparent from the higher dividend yields reflected in the DCF model that risk premiums have increased, close scrutiny should be given to the determination of a reasonable growth rate that should accompany this increased risk premium. If investors are fearful that the economy is entering a long recession, or at the very least a long period of slow growth, then the expected growth rate in the DCF model should reflect this. If equities' analysts have been slow to update their 5-year estimated earnings per share growth rates to reflect a slowing economy, then using these higher growth rates along with higher dividend yields will result in an unreasonably high estimated cost of common equity. The likely effect of using the capital asset pricing model (CAPM) without giving thought to the reasonableness of assumptions made will cause an unreasonably low estimate of the cost of common equity. As long as one uses reason and logic as to the assumptions used in the models, the end-result should be reasonable.

D. Determination of the Cost of Capital

A utility's cost of capital is usually determined by evaluating the total dollars of capital for the utility company at a specific point in time, i.e., the end of the test year or update period. 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.

A company's authorized WACC 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 valued 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.

E. Capital Structure

The capital structure Staff used for this case is GPE's capital structure on a consolidated basis, as of the end of the updated test year period in this proceeding, September 30, 2008. Schedule 8 presents GPE's capital structure and associated capital ratios. The resulting capital structure consists of 50.65 percent common stock equity, 0.76 percent preferred stock and 48.60 percent long-term debt.[7]

It is appropriate to use GPE's capital structure for KCPL's ratemaking capital structure because this represents how KCPL is financed. Additionally, KCPL's credit rating is based on GPE's overall risk, which includes the financial risk embedded in its capital structure. Because KCPL's cost of debt is impacted by the parent company's capital structure, this is the appropriate capital structure to use in estimating KCPL's rate of return. Although GPE's overall risk profile has been impacted by its divestiture of Strategic Energy and its acquisition of Aquila (now named GMO), GPE's current capital structure is reasonable and consistent with its past capital structures. Although GPE's common equity ratio averaged 47.16 percent over the most recent five years, for the most recent three years the average was 50.22 percent, which is only slightly lower than the common equity ratio as of September 30, 2008. In fact, at least in the long-term, GPE's consolidated capital structure's financial risk can be managed consistent with that of a pure-play regulated electric utility since GPE has divested its non-regulated subsidiary and acquired a regulated subsidiary. However, in the short-term, investors will assign risk to GPE based on the risk of integrating GMO's electric utility operations into GPE. It is for this reason that Staff did not assign any weight to its company-specific cost of common equity estimate in this case. Staff recommends the Commission not give any weight to the GPE company-specific cost of common equity because to do so would allow for higher costs to be passed through to ratepayers because of the risks associated with GPE's acquisition of GMO.

[7] The components don't add to 100% due to rounding issues.

F. Embedded Cost of Debt

In prior KCPL rate cases, Staff has recommended using GPE's consolidated embedded cost of long-term debt for purposes of its recommended ROR for KCPL. However, recommending the consolidated embedded cost of long-term debt for KCPL in this rate case would result in GMO's debt being included in this cost. While Staff continues to believe that matching the consolidated capital structure with the consolidated cost of debt is ideal, Staff does no believe it is appropriate in this case because GPE recently acquired GMO and the inclusion of GMO's cost of debt would result in KCPL's ratepayers paying higher rates. However, as the lines between GPE, GMO and KCPL become less distinct with the passage of time, Staff will need to revisit this issue in future rate cases.

After excluding GMO's cost of debt, GPE's embedded cost of long-term debt as of September 30, 2008, was 6.203 percent (KCPL's updated response to Staff Data Request No. 111). Consistent with Staff's explanation above, this is the cost of long-term debt embedded in Staff's ROR recommendation for KCPL.

G. Cost of Common Equity

In order to estimate the cost of common equity for KCPL, Staff performed a comparable company cost of common equity analysis of eleven electric utility companies. Staff estimated KCPL's cost of common equity using the constant-growth DCF (explained in detail in Attachment A), the CAPM (explained in detail in Attachment B) and a multi-stage DCF methodology (explained later in this section of the Cost of Service Report). In addition, Staff reviewed some other indicators to test the reasonableness of its recommendation. Staff will discuss these in more detail later in this segment of the report.

Staff started with a list of 65 market-traded companies classified as electric utility companies by Value Line (see Schedule 9). This list was reviewed for the following criteria, to develop a proxy group comparable in risk to KCPL:

1. Classified as an electric utility company by Value Line;

2. Stock publicly traded: this criterion did not eliminate any companies;

3. Classified as a regulated utility by EEI or not followed by EEI: this criterion eliminated thirty companies;

4. At least 70 percent of revenues from electric operations or not followed by AUS: this criterion eliminated fourteen additional companies;

5. Ten year Value Line historical growth data available: this criterion eliminated two additional companies;

6. No reduced dividend since 2005: this criterion eliminated four additional companies;

7. Projected growth available from Value Line and IBES: this criterion eliminated five additional companies;

8. At least investment grade credit rating: this criterion did not eliminate any additional companies; and,

9. Company-owned generating assets: this criterion did not eliminate any additional companies.

This final group of eleven publicly-traded electric utility companies (the comparables) was used as a proxy group to estimate the cost of common equity for KCPL's electric utility operations. The comparables are listed on Schedule 10.

Staff performed its traditional constant-growth DCF analysis in this case, but because of uncertainties in the market and unsustainable projected earnings growth rates, Staff decided to rely primarily on a multi-stage DCF analysis to arrive at its recommended ROE. Because of the dramatic events in the economy and the market over the last few months, risk premiums have increased. However, at the same time risk-free rates have decreased, so the overall cost of capital hasn't changed significantly. This has become apparent with the recent return of utility bond yields to pre-October 2008 levels. Staff believes the risk premiums have increased because investors have become more pessimistic about the future growth of the economy and there has been very little good news to change investors' minds about the growth potential of the economy. Although the 2008 fourth quarter GDP didn't contract as much as some had expected, it did decrease by 3.8 percent and this followed a contraction in the third quarter of 0.5 percent, which means that the economic downturn now meets the textbook definition of a recession, which is two consecutive quarters of contraction in GDP. Staff does not believe that equities analysts' earnings projections are sustainable, especially considering the state of the economy.

GPE's executive officers recently acknowledged during their 2008 third quarter earnings conference call that they believed the economy was going to impact their revenue growth. Terry Bassham, Executive Vice President and Chief Financial Officer, indicated the following:

> From a revenue perspective, we aren't looking for much in the way of weather-normalized retail demand improvement next year. The economy in our service territory is sluggish and we are looking for KCP&L demand to say about flat, with GMO growing at about the same rate as this year. That should put combined weather-normalized retail sales growth at about half a percent for the year. As we look at 2010 and 2011, we do see a bit of demand improvement at KCP&L but still below the 2% growth rates we'd seen historically. We expect GMO's growth to significantly be below the 2003-2007 average of 2.5% - 3.0% as well. On a consolidated basis in 2010 and 2011, retail sales will grow at around 1% or so.

Even normal growth rates for KCPL and GMO are in the two to three percent range and GPE is expecting these growth rates to be even lower over at least the next three years because of the sluggish growth in the economy. If investors are expecting a protracted period of slow growth in the national economy, then one would expect the growth rate for utilities throughout the country to be lower than their historical growth rates. Staff believes these lower growth projections are impacting stock prices in general and utility stock prices in particular. Investors' lower growth expectations must be factored into a cost of common equity analysis in order for such analysis to be reliable.

Because Staff decided to perform a multi-stage DCF model analysis after deciding its traditional constant-growth DCF analysis and its CAPM analysis were not reliable in this case, it will explain the latter two analyses first.

The first step Staff performed in its constant-growth DCF analysis was to estimate a growth rate. Staff reviewed the actual dividends per share (DPS), earnings per share (EPS), and book values per share (BVPS) as well as projected DPS, EPS and BVPS growth rates for the comparables. Schedule 11-1 lists the annual compound growth rates for DPS, EPS, and BVPS for the past ten years. Schedule 11-2 lists the annual compound growth rates for DPS, EPS, and BVPS for the past five years. Schedule 11-3 presents the averages of the growth rates shown in Schedules 11-1 and 11-2. As can be seen from these schedules, the historical growth rates have been volatile. Because of this volatility, Staff hesitated to give much weight to the historical growth rates in estimating investors' expectations of future growth for the proxy group. Consequently, Staff analyzed projected growth rates to determine if these growth rates might be a reliable proxy for investors' expectations of future long-term growth in the proxy group's stock price.

Staff analyzed the projected DPS, EPS and BVPS as estimated by the Value Line analyst over the next five years for each company (see Schedule 12). As can be seen from this schedule, the growth rate projections for these same indicators are also widely dispersed among the comparable companies. Staff also compared IBES analyst earnings estimates to that of the Value Line earnings estimates on Schedule 14. As can be seen from this schedule, the projected growth rates range from two percent to 13.63 percent, and average in the six to seven percent range. Staff does not believe these growth rates are sustainable, not to mention the fact that they don't make much sense in the current economic environment. Staff does not believe these growth rates should be given much weight in its constant-growth DCF analysis. Although Staff does not believe it is prudent to rely on either the historical or projected growth rates to estimate a growth rate for its constant-growth DCF model analysis, Staff nevertheless plugged in a growth rate of four to five percent because this gives some consideration to some of the high estimated EPS growth rate estimates, but tempers these growth rates because they are not sustainable. Staff emphasizes that it did not scrutinize the selected growth rates. If anything, a four to five percent growth rate is too high of a growth rate to expect as a constant-growth rate for the electric utility industry. Staff is simply using these growth rates to show a result for informational purposes only. Staff decided to use a multi-stage analysis after it reviewed the data from its traditional constant-growth DCF analysis. Consequently, Staff believed it was important to show the data it analyzed to make this decision. Just as Staff does not recommend the Commission give any weight to the GPE-specific DCF results, Staff does not recommend giving the traditional constant-growth DCF analysis any weight. As will be discussed when describing Staff's multi-stage DCF analysis, Staff believes that a sustainable perpetual growth rate is lower than four to five percent.

The next step was to calculate an expected yield for each of the comparables. The yield term of the constant-growth DCF was calculated by dividing the amount of DPS expected to be paid over the next 12 months by the market price per share of the firm's stock. Because of the recent volatility in the stock market, it is important to ensure the selection of stock prices that reflect investors' current expectations of the business and economic climate.

Because investors' expectations began to change in October 2008 due to the credit crisis, Staff believes this is the appropriate starting point. Staff believes it is important to capture all monthly stock prices since October to reflect investors' ongoing analysis of the current economic conditions and the impact it is having on their expectations of future returns and the risk of these returns. Consequently, Staff chose to use stock prices for the past four months to determine an average market price for each of the comparables. This averaging technique minimizes the effects on the dividend yield which can occur due to the volatility in the stock market. Schedule 15 presents the average high / low stock price for the period of October 1, 2008, through January 31, 2009, for each comparable. Column 1 of Schedule 16 indicates the expected dividend for each comparable over the next 12 months as projected in the most recent Value Line report. Column 3 of Schedule 16 shows the projected dividend yield for each of the comparables. The dividend yield for each comparable was averaged to estimate the projected average dividend yield for the comparables of 5.45 percent. Considering the Commission's position regarding the quarterly-compounding of dividends expressed in its Report and Order in the most recent Union Electric rate case, Case No. ER-2008-0318, it is important to note that this dividend yield has not been adjusted for quarterly compounding. Staff is attempting to estimate investors' expectations and because the Value Line quoted dividend yield does not reflect quarterly compounding, Staff is not convinced that investors' analyze the expected dividend yield on a quarterly-compounded basis. Staff will discuss another reason for not compounding quarterly when it explains its multi-stage DCF analysis.

As shown on Schedule 16, the average cost of common equity based on the projected dividend yield and a growth rate range of four to five percent is 9.40 percent to 10.40 percent. Staff believes the use of a four to five percent constant growth rate range is optimistic considering current economic conditions. Staff does not recommend the Commission authorize an ROE based on Staff's constant-growth DCF analysis in this case.

Staff performed a CAPM cost of common equity analysis on the comparables. The CAPM requires estimates of three main inputs, the risk-free rate, the beta and the market risk premium. For purposes of this analysis, the risk-free rate Staff used was the yield on Thirty-year U.S. Treasury Bonds. Staff determined the appropriate rate to be the average yield for January 2009. The average yield of 3.13 percent was obtained from the St. Louis Federal Reserve website.

For the second variable, beta, Staff used Value Line's betas for the comparable group of companies. Schedule 17 contains the appropriate betas for the comparables.

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. Staff relied on risk premium estimates based on historical differences between earned returns on stocks and earned returns on bonds. However, just as Staff warned before the recent capital market issues ensued, these risk premium estimates may not reflect the current risk premiums implied in the valuation of stock prices. Consequently, the reliability of cost of common equity results obtained from performing a CAPM analysis or risk premium analysis is heavily dependent on the estimated risk premium used to determine the cost of common equity. Although risk-free rates have dropped in the last couple of months, risk premiums have also increased in recent months. If the inputs in the CAPM analysis are not adjusted to reflect the current uncertain capital and economic environment, then the CAPM will yield illogical results. Because the estimation of implied equity risk premiums is often done by using some variation of the DCF model, Staff believes any such attempt in this case to estimate the equity risk premium for purposes of the using the CAPM model will only be as reliable as the DCF analysis used to estimate this equity risk premium. If the DCF analysis doesn't appear to be reliable, then any risk premiums estimated using a DCF analysis will be unreliable. Consequently, Staff focused its time and effort on performing a multiple-stage DCF analysis to provide what it believes to be the most reliable results in the current capital and economic environment. Nevertheless, Staff performed a CAPM analysis to show the impact that extremely low risk-free rates have had on CAPM results using the historical earned return risk premiums using both arithmetic and geometric averages.

The first risk premium Staff used was based on the long-term, arithmetic average of historical return differences from 1926 to 2007, which was 6.50 percent. The second risk premium used was based on the long-term, geometric average of historical return differences from 1926 to 2007, which was determined to be 4.90 percent. These risk premiums were taken from Ibbotson Associates, Inc.'s *Stocks, Bonds, Bills, and Inflation: 2008 Yearbook.*

Schedule 17 presents the CAPM analysis of the comparables using historical actual return spreads to estimate the required equity risk premium. The CAPM analysis using the long-term arithmetic average risk premium and the long-term geometric average risk premium produces estimated costs of common equity of 7.91 percent and 6.73 percent respectively. Staff does not believe these current CAPM results are reliable indicators of the cost of common equity for the proxy group and therefore, KCPL. According to the February 6, 2009, issue of the *Value Line Selection & Opinion*, a BBB long-term utility bond yield was 7.04 percent as of January 28, 2009. Because the CAPM result using the geometric average is below this bond yield and the CAPM result using the arithmetic average is less than 100 basis points above this bond yield, Staff does not believe a CAPM analysis based on historical risk premiums and current risk-free rates is reliable.

Because of Staff's concerns about the reliability of both its constant-growth DCF analysis and CAPM analysis in this case, Staff chose to perform a multiple-stage DCF analysis. Although other rate of return witnesses have used two-stage and multiple-stage DCF analyses in past rate cases in which Staff sponsored testimony, Staff did not believe it was then necessary because of the stability of the economy, the capital markets and expected growth rates for regulated electric utilities that seemed to be sustainable. However, that is not the situation now. Therefore, Staff believes it is appropriate to use a multiple-stage DCF analysis in order to arrive at a more reliable estimated cost of common equity.

Multiple-stage DCF methodologies are usually intended for industries and/or companies that are in the early stages of their growth cycles. In these instances, these companies/industries may have growth rates that exceed their cost of capital. In such situations, the use of a constant-growth dividend model does not provide logical results because, in order for the dividend valuation model to work, the growth rate must be less than the cost of capital. This of course assumes that the company is even paying a dividend in its early development stage. Because the utility industry is a mature industry, this is not a problem, and the constant-growth DCF is usually appropriate. However, if the industry and/or the economy are going through a period of transition, then a multiple-stage DCF analysis becomes appropriate. However, there may be sectors within the utility industry that are not as largely impacted by changes in the economy. For example, although Staff has not performed a cost of capital study on the natural gas distribution industry since the credit crisis, the constant-growth DCF may still provide the most reliable estimated cost of common equity for this industry. Many finance textbooks have used the utility industry as an example for an appropriate situation to use the constant-growth DCF model, so this methodology is still sound as long as the capital and economic environments are fairly stable and the industry is mature and stable. [8][9]

Because of the factors discussed above, Staff believes a multi-stage DCF analysis will provide the most reliable cost of common equity estimate, as long as reasonable growth rates are used at the various stages in the analysis. As with the constant-growth model, it is not the model alone that allows for reliable results, it is the reasonableness of the inputs that provide reliable results. Although the reasonableness of early-stage estimated growth rates are important in a multi-stage DCF analysis, the perpetual growth rate used will be the primary driver of the final cost of common equity estimate. While a DCF analysis of companies/industries in the early stages of their growth cycle, i.e. supernormal growth companies, may use GDP as an estimate for the perpetual growth rate, this is not reasonable for mature industries that are simply going through transition impacted by construction cycles and/or economic uncertainty. It is entirely reasonable to expect that utility companies will return back to a growth rate consistent with their real growth plus a factor for inflation. This should cause electric utility companies to settle on a perpetual growth rate of around three percent, which Staff will support later in this section of the Cost of Service Report.

Although Staff believes equities analysts' earnings growth rates may not be factoring in current economic conditions and the effect they may have on future electricity demand, Staff does realize that many electric utility companies are involved in a significant amount of construction that may improve their earnings when these projects are reflected in rates.

[8] Aswath Damodaran, *Investment Valuation: Tools and techniques for determining the value of any asset,* University Edition, John Wiley & Sons, Inc., 1996, p. 195-196.
[9] John D. Stowe, Thomas R. Robinson, Jerald E. Pinto and Dennis W. McLeavey, *Analysis of Equity Investments: Valuation*, Association for Investment Management and Research, 2002, p.64.

Therefore, Staff chose to give full weight to the analysts' earning growth estimates for the first five years of its DCF analysis and partial weight to these analyst growth rates in years six through ten. However, Staff does not believe these earnings growth rates are sustainable. For this reason, Staff chose to rely on projected electricity consumption growth and an inflation factor to estimate investors' expectations of long-term sustainable growth for an electric utility company. Staff relied on the Energy Information Administration's projection of long-term electricity consumption of approximately 0.9 percent for the period 2007 through 2030 for all sectors of the economy[10] and added the Congressional Budget Office's projected inflation of 2.2 percent over the long-term[11] to arrive at a perpetual growth rate of 3.1 percent, which is a reasonable long-term growth rate to expect for the electric utility industry. In fact, based on the current yields of long-term treasuries, the estimated inflation Staff uses is higher than the return investors are requiring for inflation based on the spread between nominal treasury bonds and treasury inflation protected securities (TIPS). For example, the yield for a 20-year nominal treasury bond averaged 3.46 percent in January 2009, whereas the yield on the 20-year TIPS bond averaged 2.46 percent in January 2009. This implies that investors are only requiring a 1 percent return for the prospects of inflation over the next 20 years. The 2.46 percent yield on the 20-year TIPS is the required real return, which is often considered as a proxy for investors' expectations of real GDP growth for the same period. If Staff had used a one percent inflation factor, then the long-term perpetual growth rate would have been 1.9 percent.

Actually, a perpetual growth rate of two to three percent appears to be consistent with long-term expected growth before the recent downturn in the economy. According to an article

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[10] "2009 Annual Energy Outlook," p. 4, *Energy Information Adminstration*
[11] "The Budget and Economic Outlook: Fiscal Years 2009 to 2019," Table B-1, *Congressional Budget Office.*

in the October 2004 issue of *Public Utilities Fortnightly,* "The Dividend Yield Trap," regulated electric utilities long-term growth expectations should not be much more than one to three percent. The article goes on further to state that the average long-term growth rate of 4.6 percent for the component utilities of the Lazard Core Utility Index was too optimistic and a "long-term growth proposition is closer to two to three percent, and then only if the industry is able to successfully execute on cost-cutting initiatives. In this regard, it is worth noting that during the past 30 years the industry has achieved a compound average growth rate of only one percent." These lower perpetual growth rates are also consistent with many of the perpetual growth rates used by equities analysts' when performing discounted cash flow analysis on utilities, including GPE. Staff believes that this information further supports its selection of a perpetual growth rate of 3.1 percent and if anything, is on the high side considering current economic uncertainties.

Instead of reducing the 5-year analyst growth rate estimates down to the perpetual growth rate in year six (this is the assumption in most 2-stage DCF analyses, which results in a lower cost of equity estimate), Staff decided to allow for a gradual decline from years six through ten and then applied the perpetual growth rate starting in year eleven because projecting company-specific growth rates past this time is futile.

When performing its constant-growth DCF analysis, Staff does not make the assumption that next year's dividend will grow at the rate of projected earnings growth because Staff does not believe this reflects investors' expectations. However, for purposes of performing its multi-stage DCF analysis in this case, Staff made this simplifying assumption because the dividend yield is not one of the components of a multi-stage formula. The dividend yield is embedded in the expected growth of dividends and the present value of the dividends equaling the current stock price of the company. This calculation is equivalent to determining the internal rate of return (IRR) for a possible investment. The IRR is the discount rate that makes the present value of all future cash flows equal to cost of the initial investment. In most cases, if the IRR is higher than the cost of capital, then the company will make the investment. As with many of the methodologies used to estimate the cost of common equity for utility companies in rate case proceedings, this model was adapted to solve for the equity investors' required rate of return. There are many situations in which cash flows are discounted to determine a current value of a proposed investment. For example, investment advisors discount expected future cash flows of a possible investment by the cost of common equity of the operation in order to provide an opinion on the "fair value" of a proposed investment. Staff will explain later why it believes its estimate of the cost of common equity using a multi-stage DCF methodology is supported by investment advisors that have estimated the cost of common equity for purposes of GPE's acquisition of the GMO properties.

Staff provides its multi-stage DCF analysis recommendation on Schedule 18. Schedule 18 shows the proxy group's overall average cost of common equity and Staff's recommended range based on this average. Staff does not recommend an adjustment to the estimated proxy group's cost of common equity because KCPL's credit rating is similar to that of the proxy group. This implies that the risk profile of the proxy group and KCPL are similar. Staff recommends an estimated cost of common equity range of 9.25 percent to 10.25 percent based on its multi-stage DCF analysis, with a point estimate of 9.75 percent. Staff recommends the Commission's authorized cost of common equity be based on the point estimate, but believes anywhere within this range is reasonable.

Staff does not believe its multi-stage DCF analysis should be adjusted upward for quarterly compounding as the Commission requested in its recent Report and Order in Case No.

ER-2008-0318. Estimating the cost of common equity necessarily involves making certain simplifying assumptions. In this case, Staff assumed that investors would receive higher dividends in the near future at the rate of earnings growth when in reality this will not happen. If Staff were to assume that investors would be able to reinvest these extra dividends that they will not receive, then this would only inflate the estimated cost of equity. For example, although Ameren is currently paying a dividend of $2.54 and according to Value Line is not expected to increase this dividend for the next five years, Staff's multi-stage DCF analysis made the assumption that this dividend would grow from years one through five at a rate of 4.50 percent per year. If Staff discounted the real dividends investors expect to receive over the next five years by its recommended cost of equity of 9.75 percent, this would result in a present value for these dividends of $9.69. If Staff discounts the dividends assumed in its multi-stage DCF analysis using the same discount rate, the result is a present value of $10.91 for these dividends. Since the second present value calculation results in a higher value, this would require a higher discount rate to match the actual dividends that investors will receive. Over this 5-year period, the discount rate (cost of common equity) has to be increased to 14.42 percent in order to achieve a present value of $9.68 for the higher dividends that most likely will not be received in the next five years. The magnitude of this difference will get much smaller over a longer period.

Staff believes its cost of common equity recommendation is reasonable because its inputs are reasonable, but Staff is aware of other cost of common equity estimates used by investment banks that advised GPE and Aquila on GPE's acquisition of Aquila (no known as GMO) that further support the reasonableness of Staff's recommendation. In fact, because these cost of common equity estimates were provided by consultants hired by GPE and Aquila for a purpose other than a rate case, Staff believes this further illustrates the unreasonableness of KCPL's witness' estimated cost of common equity in this case and in past cases.

Staff reviewed the opinions of GPE and Aquila's financial advisors (GPE received opinions from Credit Suisse Securities (USA), LLC ("Credit Suisse") and Sagent Advisors, Inc. ("Sagent"); Aquila received opinions from Blackstone Advisory Services L.P. ("Blackstone"), Lehman Brothers, Inc. ("Lehman Brothers") and Evercore Group L.L.C. ("Evercore") provided in its SEC Form S4 Filing (prospectus) filed on June 26, 2007. Although the financial advisors' opinions were summarized in the prospectus, Staff was unable to analyze the details of the costs of common equity and the overall weighted average costs of capital used by these financial advisors. Staff issued Staff Data Request No. 0113 in order to attempt to examine the assumptions made by the financial advisors in more detail, but KCPL objected to this data request as irrelevant and asserted that this information was not in its possession, custody or control. Staff considers this information relevant because the determination of discount rates used for valuation purposes is based on the financial advisors' opinions on the cost of capital, which is the very thing we are attempting to estimate when recommending an appropriate rate of return in a rate case. Although Staff is not aware of any resolution on the status of the data requested, Staff believes this information would have been helpful in more fully understanding the estimates made by the financial advisors, Staff believes it was still important to review the publicly available information provided to investors in order to test the reasonableness of both its recommendation and that of other parties.

Staff believes just the mere fact that the investment banks were estimating the cost of common equity for purposes of determining a fair value for a pure-play utility company should suffice for justifying the relevance of this information, but there are other reasons Staff believes this information is relevant, especially to the instant proceeding. First, the analysis done by the investment banks involves the operations of both Great Plains Energy's KCPL operations and GMO's electric utility operations, which are both the subject of rate cases before this Commission. Second, the analysis done by these investment banks involves estimating the cost of common equity using some of the same models used in estimating the cost of common equity in utility rate proceedings. For example, many investment banks use the CAPM to estimate the cost of common equity to determine an appropriate discount rate. Third, investment banks do a comparable company analysis to arrive at what they believe to be a "fair value." The number and type of companies can be reviewed to determine the reasonableness of the witnesses' comparable groups. Fourth, because this process involves estimating future cash flows from the utility operations, it can be evaluated to determine the reasonableness of certain estimated growth rates used in the witnesses' DCF analysis. This is true for both near-term growth rates and perpetual growth rates. Finally, the Commission can review this information to determine if investment advisors discount cash flows on an annual basis or on a quarterly basis. There may be additional information in these analyses that may be useful in testing the reasonableness of recommendations in this case, but Staff cannot identify that information because it only has access to the information provided in the prospectus.

Unfortunately, most of the financial advisors' publicly-available cost of capital estimates are based on their overall WACC, which is calculated slightly differently than it is in utility regulatory rate case proceedings. Because an after-tax cost of debt is used, the overall WACC will tend to be lower than a comparable WACC calculated in a utility rate case proceeding. Another factor that may cause a difference is the fact that investment advisors will use a current cost of debt rather an embedded cost of debt. Consequently, it is difficult to back into any of the investment advisors' estimated costs of common equity even when they provide the overall WACC, i.e. discount rate, used to discount cash flows.

Although most of the advisors did not provide their estimated cost of common equity for Aquila's Missouri regulated operations and Great Plains Energy, a couple of them did. On page 91 of the prospectus, Blackstone provided an estimated cost of common equity of 9.5 percent when estimating GPE's implied offer price to Aquila's shareholders. Evercore provided an estimated cost of common equity for Great Plains Energy of 9.0 to 10.0 percent when estimating an implied price per share range. There are also costs of equity provided in estimating Aquila's cost of equity as a continuing stand-alone entity, but these are not good tests of reasonableness since they capture the risk Aquila had because of its failed non-regulated investments. These costs of equity were estimated at anywhere from 10.14 percent to 14.0 percent.

It could be argued that the investment advisors may estimate higher costs of common equity because of the recent decline in the stock market, but Staff does not believe it would be much higher because, while risk premiums have gone up, the risk-free rates have come down. Additionally, investment-grade utility companies' cost of debt has returned to more normal levels in the past month. Regardless, Staff believes this supports its recommendations in the nine percent range during the same period in which Blackstone did its analysis. It certainly illustrates the unreasonableness of KCPL witness Hadaway's recommended ROE's which have been above 11 percent in cases during this same period.

The publicly-available information in the SEC filing also discussed perpetual growth rates used to arrive at certain stock price estimates. This information is directly relevant to this case since these can be used to test the reasonableness of the witnesses' perpetual growth recommendations in this case. Blackstone estimated an implied perpetual growth rate of 3.4 to 4.8 percent for Aquila's (GMO's) cash flows after 2013. Blackstone estimated an implied perpetual growth rate of 1.7 percent to 3.2 percent if Strategic Energy was excluded and 1.7 percent to 3.4 percent if Strategic Energy was included. While estimated perpetual growth rates may change slightly over time due to shifts in expected economic and/or industry growth, Staff believes these provide a fair test of reasonableness of perpetual growth rates in a multi-stage DCF analysis or even a constant-growth DCF analysis for that matter.

Although Staff has already provided its explanation as to why a quarterly-compounding adjustment is not needed in estimating the cost of capital, Staff also believes it is important to inform the Commission that based on the information provided in the prospectus, it does not appear that any of the financial advisors used quarterly cash flows to determine a "fair value" estimate for the acquisition of Aquila's Missouri electric utility properties.

Although Staff recommends that the Commission rely primarily on Staff's cost-of-common-equity recommendation using the multi-stage DCF analysis in this case when authorizing a fair rate of return, Staff recognizes that the Commission has expressed a preference in past cases to at least consider the average authorized returns as published by the Regulatory Research Associates (RRA).

According to RRA, the average authorized ROE for electric utility companies for 2008 was 10.46 percent based on 37 decisions (first quarter – 10.45 percent based on ten decisions; second quarter – 10.57 percent based on eight decisions; third quarter – 10.47 percent based on eleven decisions; and fourth quarter – 10.33 percent based on eight decisions).

The average authorized ROE for electric utility companies for 2007 was 10.36 percent based on 39 decisions (first quarter – 10.27 percent based on eight decisions;

second quarter – 10.27 percent based on eleven decisions; third quarter – 10.02 percent based on four decisions; fourth quarter – 10.56 percent based on sixteen decisions).

Although average authorized ROEs tend to garner the most attention in rate cases, it is also important to consider average authorized rates of return (ROR) to provide some context for average authorized ROEs. Some companies' costs of debt may cause their ultimate authorized return to be somewhat higher than the average. Although the cost of debt is only adjusted in extraordinary circumstances (for instance in Aquila Inc.'s recent rate cases, the cost of debt had been adjusted to make it consistent with investment grade costs), there may be concerns about the reasonableness of these costs. Because it is the overall ROR (not the quoted average authorized ROE) that is applied to rate base to determine the revenue requirement, it would appear that this average would also be important in testing the reasonableness of the total cost of capital.

The average authorized ROR for electric utilities for 2008 was 8.25 percent based on 35 decisions (first quarter – 8.36 percent based on nine decisions; second quarter – 8.21 percent based on seven decisions; third quarter – 8.32 percent based on ten decisions; fourth quarter – 8.09 percent based on nine decisions).

The average authorized ROR for electric utilities in 2007 was 8.22 percent based on 38 decisions (first quarter – 8.44 percent based on eight decisions; second quarter – 7.94 percent based on eleven decision; third quarter – 7.90 percent based on four decisions; fourth quarter – 8.38 percent based on fifteen decisions).

It is important to note that Staff has not researched the specifics of most, if not all, of the cases cited in the RRA reports.

H. Conclusion

Under the cost of service ratemaking approach, a WACC in the range of 7.73 to 8.24 percent was developed for KCPL's Missouri electric utility operations (see Schedule 21). This rate was calculated by applying an embedded cost of long-term debt of 6.203 percent and a cost of common equity range of 9.25 percent to 10.25 percent to a capital structure consisting of 50.65 percent common equity, 48.60 percent long-term debt and 0.76 percent preferred stock. Therefore, from a financial risk/return prospective, as Staff suggested earlier, Staff recommends that KCPL's Missouri electric utility operations be allowed to earn a return on its rate base in the range of 7.73 percent to 8.24 percent.

Through Staff's analysis, it believes that it has developed a fair and reasonable return, which, when applied to KCPL's jurisdictional rate base, will allow KCPL the opportunity to earn the revenue requirement developed in this rate case.

Staff Expert: David Murray

V. Rate Base

A. Plant-in-Service and Accumulated Depreciation Reserve

Staff is recommending plant in service ("plant") and accumulated depreciation reserve ("reserve") balances based on the actual booked amounts as of the end of the update period, September 30, 2008. This includes plant additions that have occurred since the test year ending December 31, 2007, and the related depreciation reserve balances. At the end of the true-up – March 31, 2009, - Staff will make, adjustments to the plant and related depreciation reserve balances to include plant additions placed in service during the period of September 30, 2008, through March 31, 2009, the true-up cut-off date. These additions must be "fully operational and used for service" before the cost of the plant is reflected in rates. During its analysis of the Company's plant reserve balances, Staff found the Company had made adjustments to the reserve account balances for retirement work in progress ("RWIP"). RWIP is retired plant that has not yet been classified for certain components of depreciation, namely cost of removal and salvage. The retired plant and related depreciation reserve was removed from the Company's plant and reserve account balances as of the retirement date, but the related reserve for cost of removal and salvage remained as of September 30, 2008. Thus, the reserve was overstated for this retired plant, which necessitated an adjustment to remove the no longer in service plant from the reserve balances. Staff included a line item in the Accumulated Depreciation Schedule identifying the RWIP associated with Production, Transmission, Distribution and General Plant.

Staff Expert: Karen Herrington

B. Cash Working Capital

Cash Working Capital ("CWC") is the amount of cash necessary for a utility to pay the day-to-day expenses incurred in providing utility services to its customers. When the utility expends funds to pay an expense before its customers provide the cash, the shareholders are the source of the funds. This cash represents a portion of the shareholders' total investment in the utility. The shareholders are compensated for the CWC funds they provided by the inclusion of these funds in rate base. By including these funds in rate base, the shareholders earn a return on the funds they have invested.

Customers supply CWC when they pay for electric services received before the utility pays expenses incurred to provide that service. Utility customers are compensated for the CWC they provide by a reduction to the utility's rate base. A positive CWC requirement indicates that, in the aggregate, the shareholders provided the CWC for the test year. This means that, on average, the utility paid the expenses incurred to provide the electric services to its customers before those customers had to pay the utility for the provision of these utility services. A negative CWC requirement indicates that, in the aggregate, the utility's customers provided the CWC for the test year. This means that, on average, the customers paid for the utility's electric services before the utility paid the expenses that the utility incurred to provide those services.

The Cash Working Capital Schedule 8 identifies the amount of cash working capital that has been determined using lead-lag study. Staff's CWC analysis results are reflected on the Rate Base Accounting Schedule 2 in the section "Add to Net Plant In Service." Staff's CWC analysis results were used in that schedule in the section entitled "Subtract From Net Plant" to derive the amounts indicated as Federal Tax Offset, State Tax Offset, City Tax Offset and Interest Expense Offset.

KCPL sells approximately 57% of its Account Receivables Kansas City Receivables Corporation ("KCREC"). This program increases immediate cash flow and provides access to funds through lines of credit. As a result of the immediate cash flow and the need to no longer attempt to collect on their account receivables, KCPL reduces the collection lag associated with cash working capital. Ratepayers benefit from the program since cash was generated by the sale of the receivables instead of the cash supplied by the ratepayers. More detailed information about KCPL's account receivable sales program can be found under the heading KCPL Receivable Bank Fees later in this report.

KCPL performed a lead-lag study using a method very similar to that used by Staff in previous cases. Therefore, Staff did not perform a complete, CWC analysis in this case. Instead, with the exception of gross receipts taxes, Staff relied on the calculations made by KCPL and

Staff in previous cases for CWC. However, upon review of KCPL's CWC schedule and work papers, Staff performed an independent analysis for Gross Receipt Taxes.

KCPL pays Gross Receipt Taxes (commonly referred to as franchise taxes) for the right to do business in the municipalities in which they operate. The tax is calculated based on a percentage of total revenues. This tax is listed on ratepayers' bills as a separate line item. The Company can change its tax calculations as the municipalities change their tax rates.

Staff reviewed the city ordinances for the Gross Receipt Tax ("GRT") to obtain a better understanding of how the tax was imposed and collected. Staff found the tax was based on prior months' revenues on a semi-annual, quarterly or a monthly basis. Staff also reviewed KCPL's actual tax calculations made and submitted to the cities and townships for remittance of these taxes. For example, GRT on a semi-annual basis with the payment due on January 31, 2009, would be calculated based on the revenues billed from July 1, 2008 through December 31, 2008. Staff calculated the time period from when KCPL collects these taxes from the customers to the time it remits the taxes to the taxing authorities. Based on this analysis, Staff determined that all municipalities served by KCPL require that the GRT be remitted to those taxing authorities after KCPL has billed and collected the tax amount from KCPL's customers. Since the Company remits the GRT to the taxing authorities after it collects it from its electric customers, these taxes are paid in arrears. The Company bills for the collection of the GRT along with the billing of electrical service and collects from the customers the same time as it collects for the provision of service. Customers are providing the cash for the GRT in advance of when the GRT is paid to the taxing authorities which allows the Company to have use of these funds for a significant period of time prior to making payment to the municipalities. A lead-lag study was completed which resulted in an expense lag that was considerably higher than the

Company calculated. The calculations for the gross receipts taxes are reflected in the CWC schedule (Schedule 8) as lines 22-24.

The City of Kansas City is by far the largest municipality in which KCPL provides electrical service. Kansas City has two gross receipts taxes -- the 6% GRT, which is a quarterly tax and the 4% GRT, which is a monthly tax. Both of these taxes are remitted to Kansas City after the Company collects the amounts due from its customers. Both taxes are calculated by the Company by using the preceding month or months revenues. These taxes are, in turn, remitted to Kansas City after they have been billed to and collected from the ratepayer. In the case of the quarterly gross receipts taxes, the three preceding months' revenues are the basis for the taxes. These taxes are paid to the City of Kansas City the month after the close of the quarter ended period. In the case of the monthly gross receipts taxes, the preceding one month's revenues are the basis for the taxes and they are remitted the month following the month they are collected from the ratepayer. While KCPL correctly identifies these taxes as payments in arrears, or after-the-fact, the Company treats the larger 6% quarterly payments as a prepayment. KCPL computed incorrectly the GRT lag payments included in its CWC schedule. While the Company included the GRT payment lag incorrectly in the CWC calculation it also incorrectly included the amount of GRT in its prepayments. Staff has corrected these "errors" in the CWC, and excluded the GRT from rate base.

Staff Expert: Karen Herrington

C. Prepayments

Prepayments are the costs a company incurs and pays in advance. Prepayments are treated as an asset and are reflected in the utility’s rate base. Staff included amounts in its rate base for all prepayments that KCPL requires to provide electric utility service to its customers.

Staff examined KCPL’s prepayment account balances over the last several years on a month-by-month basis. Based on this review and the variability in the monthly account balances, Staff determined the prepayment levels to include in KCPL’s rate base by calculating an average of the end of month balances for the 13-months ending September 30, 2008. Staff used this approach because there was no discernable upward or downward trend in the monthly balances.

Staff did not include prepayments related to gross receipts taxes, interest on life insurance premiums for Wolf Creek Nuclear Operating Company executives, and corrections of payroll errors that exist on KCPL's prepayment balances reflected in its books and records. While KCPL includes gross receipts taxes as a prepayment, Staff believes that these costs are actually paid in arrears and as a result, excluded these taxes from prepayments. The cash flow impact on KCPL for gross receipts taxes is reflected in Staff’s Cash Working Capital calculation as shown on Schedule 8, Cash Working Capital.

Based on conversations with KCPL representatives, Staff understands that KCPL agrees that the prepaid interest on life insurance contracts for Wolf Creek executives and the correction of payroll errors should not be reflected as a prepayment in this case. Staff will continue to review additional monthly information regarding prepayments as it becomes available through the true-up period ending March 31, 2009. (Accounting Schedule 2)

Staff Expert: Bret G. Prenger

D. Customer Deposits

Customer deposits are funds required to be provided by certain customers taking electrical service from the Company and are included in the rate base as an offset or reduction. The amount of customer deposits reflected on Accounting Schedule 2, Rate Base represents a 13-month average (September 2007 – September 2008) of KCPL’s Missouri jurisdictional customer deposits. Rate base is reduced because these funds are cost-free funds received by the Company.

In addition to the amount reflected in rate base for customer deposits, an amount for interest on customer deposits has been included as an adjustment to the income statement under Account 903. (Accounting Schedule 2)

Staff Expert: Bret G. Prenger

E. Customer Advances

Customer advances are funds typically provided by developers to the Company to build electric infrastructure in areas that have potential for future development. The amount of customer advances reflected on Accounting Schedule 2, Rate Base represents a 13-month average (September 2007 – September 2008) of KCPL's Missouri jurisdictional contributions. These advances are also used by the utility to establish electric service for potential future customers without investing a substantial amount of money at the risk of the utility and its other customers. Customer advances are included in the rate base as an offset reducing the amount of overall investment that customers must supply as a return to the utility. (Accounting Schedule 2)

Staff Expert: Bret G. Prenger

F. Customer Deposits – Interest Expense

An amount of interest relating to customer deposits has been included as adjustment to the Income Statement - Schedule 9. Staff calculated the interest for customer deposits consistent with the level of customer deposits reflected in the Rate Base -- Schedule 2 (*see* discussion in the Rate Base section of this report for customer deposits included in rate base). For this calculation, Staff used the customer deposit amount to be included in rate base, then multiplied that number by the most current prime interest rate published in the *Wall Street Journal* (7.25) plus 1%, for a total of 8.25%. Adjustment E-130 is being made to include this level of interest expense for customer deposits.

Staff Expert: Bret G. Prenger

G. Fuel Inventories

1. Coal Inventory

Staff included in KCPL's rate base an amount for coal inventory based on results Staff obtained from Staff's production cost model (fuel model). Among other things, Staff uses its fuel model to determine an appropriate mix of generation unit and purchased power utilization to match the normalized native load of an electric utility. In doing so, Staff also obtains from the fuel model an annual amount of tons of coal burned by each coal-fired generation unit during the normalized updated test year. For KCPL, Staff divided the annual tons of coal burned from the fuel model by 365 days to calculate an average daily burn by unit. Staff then multiplied this average daily burn by an appropriate number of days of coal inventory for each generation unit with an additional level of tons of coal added for basemat coal. Basemat coal is the bottom portion of the coal pile that is not fully usable as fuel due to contamination by soil, clay and other contaminants. Staff then multiplied the resulting normalized level of inventory for each unit by the delivered cost per ton of coal for use at that unit. The resulting annual coal costs for each unit were then aggregated and the aggregated amount multiplied by Staff's energy jurisdictional allocation factor to arrive at the coal inventory amount shown as coal inventory in Rate Base-Schedule 2.

2. Nuclear Inventory

To determine KCPL's nuclear fuel inventory, Staff used an 18-month average of the value of nuclear fuel that was contained in the fuel core of the Wolf Creek Nuclear Generating unit, consistent with how KCPL determined its nuclear fuel inventory. Since the Wolf Creek unit is refueled every 18 months this inventory level reflects the average nuclear fuel inventory value during a complete nuclear fuel usage cycle at Wolf Creek.

3. Oil, Limestone and Ammonia Inventories

Staff used 13-month averages to determine the inventory levels for oil, limestone and ammonia inventories, consistent with how KCPL determined its inventory levels for these items.

A 13-month average inventory reflects the Company's actual experience for the entire 12-month period by including a beginning inventory and an ending inventory. For example, if the test year were a calendar year it would begin with January 1 and end with December 31. A 13-month average would reflect the entire year by using the December 31 (January 1) balance and including each subsequent month-ending balance through the end of the year (December 31). Twelve month-ending balances from January 31 through December 31 do not accurately reflect the Company's actual experience because they ignore the impact of the period from January 1 through January 30. When inventory levels fluctuate from month to month, as they do with fuel stocks, a 13-month average is used to smooth out those levels. Staff's inventory levels for coal, nuclear, oil, limestone and ammonia are shown in Rate Base - Schedule 2.

Staff Expert: V. William Harris

H. Material and Supplies

Materials and supplies represent an investment in inventory for items such as spare parts, electric cables and poles, meters, and other miscellaneous items used in daily operations and maintenance activities by KCPL to maintain KCPL's production facilities and electric system. Staff reviewed the monthly balances for materials and supplies over the last several years because the account balances fluctuated from month to month with no distinguishable trend and Staff determined that a 13-month average was appropriate. (Accounting Schedule 2)

Staff Expert: Bret G. Prenger

I. FAS 87 – Pension Cost – Prepaid Pension Asset – Regulatory Asset

The Commission Staff and KCPL entered into a Stipulation and Agreement in Case No. ER-2007-0291 titled, "Nonunanimous Stipulation and Agreement Regarding Pension," (ER-2007-0291 Pension Stipulation). The ER-2007-0291 Pension Stipulation addressed the ratemaking treatment for annual pension cost under Financial Accounting Standard No. 87 (FAS 87), and pension settlement and curtailment accounting under Financial Accounting Standard No. 88 (FAS 88).

The ER-2007-0291 Pension Stipulation affirms the agreement regarding these matters reached and memorialized as part of the KCPL Regulatory Plan Stipulation and Agreement the Commission approved in Case No. EO-2005-0329 (the Regulatory Plan), and clarifies the accounting for pension cost allocated to KCPL's joint partners in the Iatan and LaCygne generating stations. The ER-2007-0291 Pension Stipulation also addresses the ratemaking treatment for a curtailment or settlement recognized under FAS 88, and is consistent with the Stipulation and Agreement reached between Staff and KCPL in the KCPL 2006 rate case, Case No. ER-2006-0314 (ER-2006-0314 Pension Stipulation).

There are two amounts in rate base resulting from the Stipulation and Agreements in Case Nos. EO-2005-0329 and ER-2006-0314:

1) Prepaid Pension Asset – The prepaid pension asset represents the unrecovered balance of negative pension cost flowed back to ratepayers in prior years. When this regulatory asset has been fully recovered, KCPL will be required to fund its annual FAS 87 pension cost

reflected in its financial statements under the terms of the Stipulation and Agreements in Case Nos. EO-2005-0329, ER-2006-0314, and ER-2007-0291.

2) FAS 87 Regulatory Asset – Under the terms of the Stipulation and Agreements referenced in the last paragraph, the difference between FAS 87 reflected in rates and KCPL's actual cost recorded in its financial statements is tracked and recorded as either a regulatory asset or liability, and amortized over five years in the next rate case. KCPL's rate base includes a regulatory asset as of September 30, 2008.

Both of these rate base amounts will be trued-up as of March 31, 2009, during the true-up audit scheduled for this case, Case No. ER-2009-0089. (Rate Base Schedule 2)

Staff Expert: Paul R. Harrison

VI. Income Statement - Revenues

A. Rate Revenues

1. Introduction

This section describes how Staff determined the level of KCPL Operating Revenues. Since the largest component of operating revenues result from rates charged to KCPL's Missouri retail customers, a comparison of operating revenues with cost of service is fundamentally a test of 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 KCPL charges its Missouri retail customers for electricity is required.

One of the major tasks in a rate case is 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 revenue) prospectively. Operating Revenues are composed of Margin from Off-system Sales, Other Operating Revenue, and Rate Revenue.

Rate Revenue: Test year rate revenues consist solely of the revenues derived from KCPL's charges for providing electric service to its Missouri retail customers. KCPL'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, energy); and to customers in different rate classes.

2. 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.

The purpose of Staff's adjustments to test year (January 1, 2007- December 31, 2007) 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 (September 30, 2008). The two major categories of revenue adjustments are known as "normalization" and "annualization”. Normalization deals 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, e.g., test year weather. 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.

This report briefly describes the following regulatory adjustments Staff made to test year billed rate revenues:

a. weather normalization
b. annualization for the rate change on January 1, 2008
c. 365-day adjustment
d. customer growth
e. large customer annualization and rate switching

f. special contracts and other customer discounts

Not all adjustments affect both sales and rate revenue. Not all rate classes are subject to all seven adjustments.

3. Regulatory Adjustments to Test Year Sales and Rate Revenue

a. Weather Normalization

i. The Purpose of (Need for) Weather Normals for Weather Normalization

The actual weather experienced during the test year is unique and unlikely to be repeated exactly in each of the years when the new rates from this case will be in effect. Thus, kWh sales are adjusted to the level that would be expected under “normal” weather.

The time period used in determining the normal values of weather variables is the 30-year period (January 1, 1971- December 30, 2000) as used by NOAA[12]. NOAA, states that “climate normal is defined, by convention, as the arithmetic mean of a climatological element computed over three consecutive decades.” However, NOAA’s adjustments are applied to *monthly* temperatures over the period, and as a result they do not contain *daily* variation in temperature for weather-normalizing electricity use. The weather normalization process requires *daily* temperature normals, because electricity usage varies differently at extreme daily temperatures than it does at mild daily temperatures. Consequently, Staff adjusted its daily data to correspond with the NOAA monthly average.

Staff used daily temperatures from Kansas City International Airport (MCI) to develop “normal” or average temperatures with which to compare test year temperatures. The data required to weather normalize sales are the actual and normal two-day weighted mean daily temperatures. To calculate the two-day weighted mean temperature, the current day’s mean

[12] National Oceanic and Atmospheric Administration

temperature is averaged with the prior day's mean temperature applying a 2/3 weight on the current day and 1/3 weight on the prior day. This is done in order to carry forward the previous day's residual effect on the current day's usage.

Normal Weather Ranking. The ranking method estimates daily normal temperature values, ranging from the temperature that is "normally" the hottest to the temperature that is "normally" the coldest, thus estimating normal extremes. The daily temperature normals are estimated 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. Because actual temperatures do not smoothly increase or decrease during the year,[13] these normal temperatures are then assigned to the days of the test year based on the rankings of the actual temperatures of the test year.

Staff uses normal weather in both the normalization of class usage and hourly net system loads. KCPL used the same method to calculate daily normal weather values. This information was used in the review of KCPL's weather normalization.

Staff Expert: Manisha Lakhanpal

ii. Weather Normalization of kWh Sales

Consumption of electricity is sensitive to weather conditions. Demand for electricity for air conditioning increases as temperature increases, resulting in saturation at high temperatures. As temperature declines, usage of space heating increases, resulting in a similar, though less drastic response. The magnitude and shape of KCPL's response to temperature is, therefore, related to usage of air conditioning and space heating.

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[13] For example, in July a Monday and Tuesday may be hot days but it cools down on Wednesday. However, it is still likely that on the weekend it will be hot again.

Winter and summer temperatures during the 2007 test year fluctuated resulting in both cooler-than-normal and warmer-than-normal months in each season. Staff reviewed KCPL's data and weather normalization methodology and agrees with, and therefore adopts, KCPL's results for the Residential, Small and Large General Service classes in Missouri. KCPL's 2007 Billing Month Adjustments for weather are found on Schedule 4-1.

Staff does not adopt KCPL's Large Power Class' weather normalization. Relative to the other classes, the Large Power Class consists of a small number of customers, and therefore, is examined by Staff on an individual customer basis. When monthly data is either missing or is inconsistent with its historical trend, Staff creates estimates to complete the data set. For some customers, months of data may need to be estimated or otherwise corrected. This process is referred to as annualization and is discussed in *Section e, Large Customers and Rate Switching*.

Once an individual customer's electric usage is annualized, and the class members' loads are summed to determine the class load, the resulting load is an estimate because it is based on estimates. Furthermore, the class is populated by businesses with operations that differ from one another both in size and industry type. There are businesses in the class whose activities are more sensitive to the economic cycle than to the weather. The presence of such businesses in the class inflates electric usage such that the class appears to be more weather sensitive than it is.

Staff Expert: Walter Cecil

iii. The Effect of the Weather Normalization of kWh Sales on Rate Revenue

In order to calculate weather-normalized revenue, current rates were applied to weather-normalized sales. The difference between these weather-normalized revenues and the test year revenues, determined the amount of the adjustment.

An underlying assumption of the weather normalization process is that such a process has no effect on either the number of customers or on the fixed charges these customers currently pay. Weather normalization only affects the energy usage of each existing customer and thus it only changes revenue directly related to kWh sales. Staff reviewed and accepted that KCPL had adjusted sales for rate switchers[14] prior to weather normalization. The total annual weather normalization of test year revenues is a reduction to revenues by ($10,346,344) for all weather sensitive rate classes.

Staff Expert: Manisha Lakhanpal

b. Annualization for Rate Change

Test year rate revenues do not reflect any of the rate changes implemented on January 1, 2008 as an outcome of Case No. ER-2007-0291. Thus, for all rate classes, 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 computed annualized revenues on 2008 rates for each rate class by applying 2008 rates to test year annualized, normalized billing units for each class. The total annualization for rate change to test year revenues results in an increase of $36,999,746.

Staff Expert: Manisha Lakhanpal

c. 365-Days Adjustment

A "days" adjustment was done for both Missouri and Kansas jurisdictional sales. Since revenue months are an aggregation of bill cycles, they will differ from calendar months in the time period they cover. A bill cycle is approximately a 30-day period between a customer's

[14] Rate Switchers are primarily industrial and commercial customer accounts that switch between different rate groups that better suits their consumption pattern.

meter readings, e.g., June 17 to July 17 or July 18 to August 17. For example, the usage from June 17 to July 17 would be included in the revenue month of July for that customer. But, only the usage from July 1 to July 31 is included in the calendar month of July. To account for this difference, a "days" adjustment was to adjust the level of annual weather normalized revenue month kWh sales to coincide with the annual, weather normalized, calendar month kWh sales. The “days” adjustment was calculated by taking the difference between the weather normalized calendar month sales over the test-year, and the weather normalized revenue month sales over the test-year. The “days” adjustments to both Missouri and Kansas sales were used in calculating the energy jurisdictional allocator.

A revenue adjustment was calculated for Missouri weather sensitive classes by allocating the “days” adjustment proportionately to the appropriate revenue month weather normalized kWh sales for each class and then applying current rates. The difference between the revenues calculated in this way for each class and the test year revenues for the class determined the amount of the 365-days adjustment.

For the Large Power (LP) rate group, depending on the number of usage days in a bill cycle, an adjustment is made by either adding days of usage when there were less than 365 days of usage, or subtracting days of usage when there were more than 365 days of usage to a customer's annual sales. The differences between the revenues produced by the "days" adjusted sales and the actual sales are the “days” adjustments.

"Days" adjustments are also known as adjustments to "unbilled" sales and "unbilled" revenues on financial statements. KCPL’s Missouri jurisdiction’s total annual “days” adjustment of test year revenues reflects a reduction of ($841,925).

Staff Experts: kWh - Walter Cecil; Revenue- Manisha Lakhanpal

B. Customer Growth

Customer growth adjustments were made to test year kWh sales and rate revenue to reflect the additional kWh sales and rate revenue, which would have occurred if the number of customers taking service at the end of the update period (September 30, 2008) had existed throughout the entire test year. Customer growth was calculated for the Residential, Small General Service, Medium General Service, and Large General Service rate classes using customer levels as of September 30, 2008. Cognizant of the Commission's Report and Order in KCPL's last rate case, Case No.ER-2007-0291, Staff ensured that KCPL has restricted the availability of its general service all-electric and separately-metered space heating discounted rates to those qualifying customers being served under such rates as of January 1, 2008.

Staff Expert: Kofi Agyenim Boateng

C. Additional Revenues from Customer Growth During the Update Period

For this direct testimony filing, the Commission has ordered all elements of revenue, expense, and rate base be updated over the 2007 test year level for any known and measurable changes through September 30, 2008. A review of the pertinent facts at September 30, 2008, indicates that KCPL has experienced an increase in its revenues since the end of the test year, due to overall growth in the number of its utility customers. For Residential and General Service (Small, Medium, and Large) retail customer groups, Staff has employed the following method of computing the annualized level of increased revenue from customer growth at September 30, 2008. For each customer rate group, the customer level during each month of the test year is compared to the level at September 30, 2008, and the monthly change in level is computed. This growth in customers is then multiplied by the weather-normalized revenue per customer experienced for that month of the test year. The total growth in revenues is arrived at by performing this comparison and multiplication for each month of the test year, and then summing the results. In short, this approach assumes that the revenue pattern experienced in each month of the test year will recur, on a weather-normalized basis, factored up (or down) in accordance with the growth (or decrease) in customer numbers at September 30, 2008.

The only retail customer rate group for which this approach is not taken is the Large Power group. With respect to Large Power customers, energy consumption and revenue patterns are considered to vary sufficiently 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. Staff's customer growth adjustment to test year revenues for all retail customer groups combines the results of the analysis described above for Residential, General Service, and Large Power in order to provide the annualized level at September 30, 2008. The adjustment for retail customer growth other than Large Power is Rev-2.9.

Staff Expert: Kofi Agyenim Boateng

D. Large Customer Annualization and Rate Switching

The general purpose of an annualization is to re-state test year kWh results as if conditions known at the end of the update period had existed throughout the entire test year. Because each Large Power (LP) 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. This process takes care of any major growth or decline in kWh sales and rate revenues due to the entrance of new customers, the exit of existing customers, and load growth or decline of specific existing customers. A major component of the large customer annualization process consists of gathering twelve months of representative usage and revenue data for each large customer active at the end of the update period.

At the end of the test year, there were ninety-eight customers in the LP rate group. A data check for billing corrections was done prior to making any adjustments. Each customer's individual monthly demand and energy use, measured over multiple years prior to the test year and the twelve months of the test year, were examined graphically to determine whether an adjustment was needed.

Five customers rate switched out of Large Power (LP) into Large General Service (LG) rate group, and four LP customers quit taking service from KCPL during the test year, so total LP load was reduced by the load amount of the above mentioned customers. Six customers switched into the LP class from the LGS class, three during the test year, and three during the update period. This adjustment was made by moving the test year usage data of these customers for the affected months from LG to LP. Large Power rate switching adjustment is equal to $938,877.

Six new customers joined the LP class, three during test year and three during update period. In the case of those new customer accounts with less than twelve months of billing information missing data was estimated by taking an average of the given data. Annualization for new customer accounts, which were added to the rate group, is an adjustment of $6,728,869.

In the Kansas jurisdiction only three customers remained in the rate group at the end of the test year while sixty customers rate switched into other classes. The LP class load was reduced by the load of the customers who left the rate class.

Staff Expert: Manisha Lakhanpal

E. Special Contracts and Other Customer Discounts

Special Contracts: There are Missouri LPS customers who pay a discounted rate for electricity because of special contracts that each has with KCPL. Pursuant to the KCPL

Regulatory Plan, Staff has "imputed" the revenue from these contracts (i.e., calculated revenue as if the discounts did not exist) to ensure that these discounts will be "paid" by shareholders and not by any of KCPL's other ratepayers.

PLCC/MPower: Peak load curtailment credits are paid to customers that agree to curtail a portion of their peak load when requested by KCPL. These discounts are assumed to be a benefit to all ratepayers and thus are not excluded from the determination of KCPL's revenues.

EDR: The Economic Development Rider (EDR) provides for discounts to be "paid" to customers (in the form of credits on their electricity bill) who locate or expand operations in KCPL's service territory. EDR credits are provided to the customer over a five-year period. The value of the credits is a percentage of the customer's electric bill calculated on the appropriate general application rate schedule. Depending upon the contract year the customer is in, the discount can be as high as 30% (year 1) to as low as 10% (year 5). Staff assumed that the annualization for the rate change would be reflected in both the level of the bill before the credit and in the amount of the credit itself (i.e., a 10% rate change would increase both the pre-credit bill and the EDR credit by 10%). These discounts are included in the determination of KCPL's revenues because fostering economic development is assumed to be a benefit to all ratepayers.

The results of test year adjustments to kilowatt hour sales for both the Missouri and Kansas jurisdictions (Attachment ML1) were used in the calculation of Net System Input Sales (NSI). Normalized Rate Revenue summary for the Missouri jurisdiction can be found as an attachment to the Staff Accounting Schedules.

Staff Experts: Manisha Lakhanpal

F. Bulk Power Sales

1. Deferred Sales from SO_2 Emissions Allowances

Since KCPL receives more SO_2 emission allowances (SO_2 allowances) from the U.S. Environmental Protection Agency (EPA) than it requires for its own coal-burning operations, it may sell all or part of the surplus allowances. Under the FERC uniform system of accounts (FERC USOA), proceeds from the sales of surplus SO_2 emissions allowances are recorded in FERC account 254, the FERC USOA regulatory liabilities account, to increase the balance of that account. For ratemaking, amounts recorded as regulatory liabilities reduce a utility's rate base, i.e., the net amount in FERC account 254, after any appropriate adjustments, is an offset to rate base.

Staff has included in its updated September 30, 2008 case the balance of account 254 as an offset to rate base. This approach is consistent with the treatment in the last two KCPL Rate Case Nos. ER-2006-0314 and ER-2007-0291. The rationale for treating the SO_2 emissions allowances in this manner is to acknowledge that, through rates, KCPL's customers have paid for KCPL's production facilities that create these SO_2 emissions allowances which KCPL is then able to sell to others.

Staff Expert: V. William Harris

2. FERC Account 447-Bulk Power Sales Includes Three Sources of Revenue for KCPL

<u>a. Firm Off-System Sales</u>

KCPL has two customers who have a capacity contract with KCPL. These customers are the City of Springfield, Missouri and the City of Independence, Missouri. Under their respective contracts, these customers pay both a demand charge for the megawatt capacity commitment from KCPL and an energy charge for the cost of delivered energy. During the test year, KCPL made energy sales to two other customers that KCPL classified as Firm Off-System Sales customers:

1. Kansas Municipal Energy Agency (KMEA)
2. Missouri Joint Municipal Electric Utility Commission (MJMEUC)

b. Non-Firm Off-System Sales

Non-firm off-system sales are sales of electricity made at times when a utility has met all of its obligations to serve its native load customers (rate tariff customers) and firm sale customers, and has excess electricity it can sell to others. Off-system sales result in profits (net margin) to the selling utility, in this case KCPL. Off-system sales are typically made at market-based rates. The aggregate profits of these off-system sales are used to lower the electric utility's revenue requirement.

c. FERC Wholesale Sales

FERC wholesale customers are municipalities that buy electricity under a firm power tariff regulated by the FERC. Since the wholesale customers are treated as another jurisdiction, none of the revenues from these customers are included in Missouri's regulated operations. Staff allocates to Missouri the plant-in-service, revenues, fuel and purchased-power costs required to serve Missouri customers using demand and energy allocation factors developed by Staff expert Alan Bax. The FERC jurisdictional loads are not included in the demand and energy allocators developed for the Missouri jurisdiction.

d. Firm Off-System Sales

KCPL has made an adjustment in this case to remove the firm energy revenues from KMEA and MJMEUC and reflect them as non-firm off-system sales because KCPL's contracts with these customers expire on May 31, 2009. The Company is not certain if these agreements will be renewed at this time. The termination of these contracts is outside the March 31, 2009 true-up Ordered by the Commission. KCPL has indicated that the reduction of sales for the loss of these two customers have "freed-up" energy which has been reflected in the non-firm off-system sales model used by KCPL to support the margin levels it proposes in this case. If this is in fact the case, then the non-firm off-system sales margins calculated using this model are higher than they would be absent this case.

In addition to the change in the model to reflect the expected termination of the KMEA and MJMEUC agreements, Staff has recently learned that KCPL has changed its position regarding off-system sales levels it originally supported in its September 30, 2008 direct filing. Currently, Staff cannot make the determination if the increase in off-system sales has occurred from the expected loss of KMEA and MJMEUC. While KCPL's initial filing had off-system sales levels that would support the position that the lost firm customers were made up in non-firm off-system sales, the Company's updated case has substantially reduced the level of off-system sales it now claims should be included in the case. Therefore, Staff will continue to review the adjustments proposed by KCPL regarding off-system sales for both firm and non-firm customers. After obtaining and reviewing additional information, Staff will make a determination on the appropriateness of making any of these adjustments.

e. Non-Firm Off-System Sales Results

The Commission, in both Case Nos. ER-2006-0314 and ER-2007-0291, adopted and relied on KCPL consultant Michael M. Schnitzer's projected level of net margin at the 25th percentile for the net margin of non-firm off-system sales to include in KPCL's cost of service. Mr. Schnitzer has updated his analysis for this case and filed his findings on September 5, 2008 as part of the Company's original direct filing. Staff has included Mr. Schnitzer's original projected level of net margin of ** ______ ** million, total company, at the 25th percentile in determining KCPL's cost of service.

The Commission's Report and Order and Order Regarding Motions for Rehearing in Case No. ER-2006-0314 included a requirement, on page 36, to track the net margin included in cost of service with KCPL's actual net margin on an annual basis. As part of the Commission's decision in the 2006 rate case, if KCPL's actual net margin exceeded the Missouri jurisdictional level of ** __________ ** included in cost of service in Case No. ER-2006-0314, KCPL was required to reflect the difference in a regulatory liability account and flow back the excess to ratepayers as a reduction to cost of service in KCPL's next rate case. Since rates in Case No. ER 2006-0314 became effective, January, 1, 2007, the first annual period that must be tracked in accordance with the Commission's Report and Order in Case No. ER-2006-0314 is the twelve-month period ending December 31, 2007. There was an amount in excess of the level found by the Commission in Case ER-2006-0314 for non-firm off-system sales margin for 2007. Staff witness Charles R. Hyneman has reflected the excess above the amount determined by the Commission in the 2006 rate case for the twelve months ended December 31, 2007 in the amount of ** _________ ** in this case.

On page 39 of its Report and Order in Case No. ER-2007-0291, the Commission required that the off-system sales net margin included in cost of service be tracked against KCPL's actual off-system sales net margin on an annual basis. If KCPL's actual off-system sales net margin exceeds the Missouri jurisdictional level of ** ____________ ** included in cost of service in Case No. ER-2007-291, KCPL is required to reflect the difference in a regulatory liability account and flow back the excess to ratepayers as a reduction to cost of service in KCPL's next rate case. Since rates in Case No. ER 200-0291 became effective, January, 1, 2008, the second annual period that must be tracked in accordance with the Commission's Report and Order in Case No. ER-2007-0291 is the twelve-month period ending December 31, 2008. There was an amount in excess of the level found by the Commission in Case ER-2007-0291 for non-firm off-system sales margin for 2008. Staff proposes to treat the 2008 excess above the Commission approved level in the same manner as described by Staff witness Charles R. Hyneman for the 2007 excess above the amount determined by the Commission in the 2006 rate case. The twelve months ended December 31, 2008 amount is over ** ________ ** (total Company) in excess of the level found in the 2007 rate case of ** ________ ** on a total Company basis. Staff proposes to treat this excess on a jurisdiction level in the true-up as an adjustment.

Consistent with reflecting Mr. Schnitzer's current projected net margin at the 25th percentile in KCPL's cost of service in this case, Staff is recommending a continuation of the net margin tracking mechanism the Commission ordered in Case No. ER-2007-0291 that requires KCPL to track its actual annual results and account for an excess above the amount ordered by the Commission on a Missouri jurisdictional basis, as a regulatory liability to be reflected as a reduction to cost of service in the next KCPL rate case.

f. Non-Firm Off-System Sales Annualization

KCPL is proposing two adjustments to Mr. Schnitzer's determination of the net margin from Non-Firm Off-System Sales at the 25th percentile. The first adjustment removes the Southwest Power Pool (SPP) charges for line loss (net of line loss revenue) from Mr. Schnitzer's projected margin. The second adjustment removes purchases for resale from Mr. Schnitzer's calculation. These adjustments are sponsored by KCPL witness Burton L. Crawford.

As noted above, KCPL removed off-system sales for two agreements expected to be terminated in May 2009 which is beyond the true-up cut off in this case. Normally Staff would be opposed to such adjustments as out of period and beyond the scope of this case but KCPL has stated that the model used by KCPL to annualize non-firm off-system considered the freed up energy resulting in higher non-firm off-system sales margin. However, Staff has recently learned that KCPL has changed its position regarding off-system sales levels it originally supported in its September 30, 2008 direct filing as result of lower natural gas prices than what was originally used. Currently, Staff can not make the determination if the increase in off-system sales which was supposed to have occurred as result of the loss of KMEA and MJMEUC has actually occurred. While KCPL's initial filing had off-system sales levels that would support the position that the lost firm customers were made up in non-firm off-system sales, the Company's updated case has substantially reduced the level of off-system sales it now claims should be in the case. Therefore, Staff will continue to review the adjustments proposed by KCPL regarding off-system sales for both firm and non-firm customers. After obtaining and reviewing additional information, Staff will make a determination on the appropriateness of making any of the adjustments proposed by KCPL.

Staff has also made an adjustment to reflect off-system sales that KCPL treats on its book as below the line sales. While KCPL has not technically made an adjustment to remove these sales (referred to as "Q-sales") booking these transactions below the line has the same effect as making an adjustment to remove them from the revenue requirement determination. KCPL agreed not to make any adjustments to remove off-system sales from future rate cases, based on the Regulatory Plan wherein it is stated that "KCPL agrees that off-system energy and capacity sales revenues and related costs will continue to be treated above the line for ratemaking purposes" and "not to propose any adjustment that would remove any portion of its off-system sales from its revenue requirement determination in any rate case." The Q-sales were effectively removed without KCPL ever making an actual adjustment.

Adjustment Rev-10.1 in Staff's accounting schedule 10 reflects the net margin from Non-Firm Off-System Sales at the 25th percentile projected by KCPL witness, Michael M. Schnitzer for this case, Case No. ER-2009-0089.

Staff Expert: V. William Harris

G. Miscellaneous Revenues

<u>1. Late Payment Revenue (Forfeited Discount)</u>

KCPL charges its customers late payment fees for non-payment of customer bills in a timely manner. Staff annualized late payment revenues by using the ratio of forfeited discount to Missouri Total Retail Sales from October 1, 2007 through September 30, 2008. This ratio was multiplied by the Staff annualized revenue, plus test year gross receipt taxes (GRT); since GRT is assessed on revenue generated from late payment fees, the calculation of the Missouri adjustment is based on Total Revenue including GRT. This is in reflected Staff Accounting Schedule as adjustment Rev-16.1.

Staff Expert: Kofi Agyenim Boateng

<u>2. Other Revenue Accounts</u>

Staff reviewed the amounts KCPL included in its cost of service calculation for Other Revenues, which include miscellaneous service revenues, rent from electric property, replacement of damaged meters, disconnect service charge, temporary installation profit, and other transmission service revenues, among others. The analysis of these amounts included a review of the revenues over the last seven years through September 30, 2008. In Staff's opinion, the test year Other Revenues amounts appeared to be representative and reasonable of an annualized level of revenue for each respective category and, therefore, do not require adjustment. However, Staff will apply its own allocation factors to those amounts that are common to other KCPL's operational jurisdictions. Staff will examine these revenue accounts again during its true-up audit through March 31, 2009.

Staff Expert: Kofi Agyenim Boateng

3. Off-Set of Fly Ash Sales (Steam Operations Solid By-Products)

This adjustment reflects the additional revenues received by KCPL for the sale of fly ash to off-set the costs associated with steam operations. Fly ash is a by-product of coal-burning power plants. KCPL entered into a new contract to sell fly ash in the summer of 2007 with Lafarge, a supplier of construction materials who recycles this by-product by adding it to cement. Thus, the 2007 test year per books do not reflect a full year of the additional revenues. Staff annualized the test year's fly ash revenue by using the amount received in 2008, the first full year under the new contract. Staff will continue to review this transaction as additional information being pursued becomes available. This is adjustment E-11.2

Staff Expert: Kofi Agyenim Boateng

VII. Income Statement - Expenses

A. Fuel and Purchased Power Expense

Staff's adjustments to annualize and normalize KCPL's fuel and purchased power expense are reflected in adjustments E-5.4, E-28.2, E-56.2 and E-71.1 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 Staff's fuel model, but were determined separately. The non-variable fuel costs that were determined separately and included in fuel expense are typically referred to as fuel adders. The non-variable purchased power costs not included in Staff's fuel model are commonly referred to as capacity charges and are annualized separately from purchased power energy costs.

2. Fixed Adders

As described above, fuel adders do not vary directly with the amount of electricity produced, so these costs are not included in Staff's fuel model. The costs of fuel adders are determined separately and are added to the level of fuel expense calculated by the model to determine overall fuel expense. Costs added to coal expense include unit train lease payments and unit train maintenance costs. Fuel adders for natural gas include transportation charges and hedging costs. A significant percentage of natural gas transportation charges is fixed and under contract.

Staff used the actual cost KCPL incurred in calendar year 2007 (test year) as its annualized level for all fuel adders in this direct filing.

Staff Expert: V. William Harris

3. Purchased Power - Energy

Staff adjustment E-70.2 annualizes purchased power energy charges based on Staff's fuel model results. These purchased power energy charges represent the energy KCPL purchases on the spot market and through contracts to meet the system load requirements of its retail electric customers. Staff expert Leon Bender is responsible for determining the appropriate amount of power purchased and the proper price for this power.

Staff Expert: V. William Harris

3. Purchased Power – Capacity Charges

Capacity charges, commonly referred to as demand charges, represent fixed amounts paid to the entity that reserves the megawatt capacity for KCPL. KCPL contracts this power with various entities and pays a fixed component for the reserve capacity and an energy component for energy consumed. Generally, there is also an amount for operational and maintenance costs charged for the usage 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 E-71.1 annualizes purchased power demand charges based on existing capacity contracts in effect. These charges represent amounts that are paid under capacity agreements related to the fixed costs of reserving capacity. Staff reviewed each of these contracts and determined the appropriate costs per megawatt hour and the amount of megawatts purchased. Staff included the costs reflected in KCPL's capacity agreements that were in effect on September 30, 2008.

Staff Expert: V. William Harris

4. Variable Costs

Staff estimates the variable fuel and purchased power expense for KCPL for the updated test year ending September 2008 to be $233,271,160.

Staff used the RealTime ® production cost model to perform an hour-by-hour chronological simulation of KCPL's generation and power purchases. Staff used the model to determine annual variable cost of fuel and net purchased power energy costs and fuel consumption necessary to economically meet KCPL's load during the test year as updated, within the operating constraints of KCPL's resources used to meet that load. These amounts are supplied to Auditing Staff who use this input in annualizing 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 Staff are: fuel prices, spot market purchased power prices and availability, hourly net system input (NSI), and unit planned and forced outages. Staff relied on KCPL 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 KCPL'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

b. Fuel Prices

Staff computed the fuel expense using prices and quantities incurred by KCPL through September 30, 2008. This included using fuel prices for nuclear, coal, natural gas and oil, including transportation charges in fuel accounts 501 (coal), 518 (nuclear), 547 (natural gas) and 555 (energy portion of purchased power expense).

b. Coal Prices

Staff's determined its coal price by generation facility based on a review and analysis of KCPL's coal purchase (supply) and coal transportation (freight) contracts. Staff's proposed coal prices reflect KCPL's actual contracted coal purchase and transportation prices (excluding sulfur premiums or discounts) in effect at September 30, 2008.

Staff Expert: V. William Harris

c. Natural Gas Prices

The natural gas prices used as an input to Staff's fuel model were calculated using an 18-month weighted average of KCPL's actual commodity cost of natural gas. KCPL's natural gas transportation costs are annualized and normalized separately as a part of fuel adders.

Staff Expert: V. William Harris

d. Nuclear Fuel Prices

KCPL owns 47% of Wolf Creek Nuclear Operating Corporation (WCNOC), the operating company for Wolf Creek. KCPL's 47% ownership interest in WCNOC entitles it to 548 megawatts of the plant's capacity. In making its nuclear fuel price proposal, Staff relied upon KCPL's monthly Report 25, Fuel Report, for 2007 through September 2008. Staff noted that monthly nuclear fuel costs over the last few years varied within a small range. Staff's proposed nuclear fuel price is based on an average of the monthly fuel costs incurred over the 18-month period from April 2007 through September 2008.

Staff Expert: V. William Harris

e. Oil Prices

Staff used the actual cost KCPL paid for its most recent fuel oil purchases. KCPL burns fuel oil mainly as a secondary fuel or, in some instances, for flame stabilization. Oil is only a primary fuel source at KCPL's Northeast units, which sees very limited run time. As a result, KCPL purchases fuel oil infrequently. The limited number of purchases of fuel oil makes it difficult to employ any meaningful type of averaging method. An accurate historical analysis of fuel oil prices is also not possible because KCPL does not make purchases during the majority of the year. Thus, any trend in costs could be misleading because of the limited amount of available data. Staff believes KCPL's most recent fuel oil purchase prices are the best available fuel oil cost to input into the fuel model for determining KCPL's variable fuel and purchased power expense on a going forward basis.

Staff Expert: V. William Harris

5. 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.

Staff used a procedure developed by the Commission's Energy Department – Engineering Section in 1996 that is described in "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.

Actual hourly non-contract transactions prices for KCPL and GMO during the update period are obtained from the data that the Companies supplied to comply with 4 CSR 240-3.190 and are used as price inputs in the calculation. Staff used the combined data from both KCPL and GMO to reflect the market that exists in this region. The calculation yields a spot energy price for each hour of the year.

Staff Expert: Daniel I. Beck

6. Capacity Contract Prices and Energy

Capacity contracts are contracts for a specific amount of capacity and a maximum amount of hourly energy. Energy for two of the capacity contracts held by KCPL are purchased at market prices therefore they were not included in the production cost model. Two other contracts are for energy from units which can be dispatched by KCPL. Those two units are included in the production cost model as dispatchable units.

Staff Expert: Leon C. Bender

7. Hourly Net System Loads

Hourly net system load is the hourly electric supply necessary to meet the energy demands of both the company's customers and the company's own needs. The hourly loads used in the analysis of the test year January through December, 2007 were provided to Staff in response to Data Request number 195. Hourly load data submitted monthly by KCPL in compliance with the Commission's rule 4 CSR 240-3.190 was used to cross check and correct errors found in the data request response.

Due to the high saturation of air conditioning and the presence of electric space heating in KCPL's electric service territory, the magnitude and shape of KCPL's net system input is directly related to daily temperatures. The actual daily temperatures for the test year differed from normal conditions. Therefore, to reflect normal weather, daily peak and average net system loads were adjusted independently, but using the same methodology. Independent adjustments are necessary because average loads and peak loads respond differently to weather.

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. The adjustments for each day are added respectively to the actual average and peak loads for each day. Actual and normal daily temperatures developed using the average and ranking methodology described in this report was used in this analysis.

The starting point for allocating both the weather-normalized daily peak and the weather-normalized average loads to the hours was the actual hourly loads. A unitized load curve was 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, were then 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" [15].

Once Staff's weather normalized, annualized test year kWh usage for both Missouri and non-Missouri customers were completed, the weather normalized wholesale usage was added. This sum was then increased by the annual usage by the loss factor to obtain the additional amount of generation (net system input) necessary to serve this kWh usage. This produced an annual sum of the hourly net system loads that equaled 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

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[15] Weather Normalization of Electric Loads, Part A: Hourly Net System Loads" (November 28, 1990), written by Dr. Michael Proctor, Manager of the Economic Analysis Department.

consistent with normalized revenues. Then, the Firm Capacity Contract Customers' hourly loads were added to the factored net-system load. A table showing each of these adjustments to attain the annual sum of the net-system hours is shown on the Summary of Net-System Input Components tab in the Staff Accounting Schedules.

Once completed, the test-year hourly normalized system loads were used in developing the test year fuel and purchased-power expense. The annual requirement of the net system hours was used in developing Staff's jurisdictional energy allocator.

Staff Expert: Shawn E. Lange

a. Normal Weather

Please refer to the revenue section of this report 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 KCPL'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.

System energy losses are calculated as a percentage of Net System Input (NSI). NSI is equal to the sum of retail and wholesale sales, plus energy used in KCPL's facilities (Company Use), plus system energy losses. Therefore, system energy losses may be calculated using the following equation:

- System energy losses = NSI – (Retail Sales + Wholesale Sales + Company Use).

NSI is also equal to the sum of net generation plus the net of off-system purchases and sales (net interchange). Net generation and net interchange are known quantities, as are Retail

Sales, Wholesale Sales and Company Use. Therefore, system energy losses may be determined using the aforementioned equation. Then, the resultant ratio of system energy losses to NSI multiplied by 100 ((system energy losses/NSI) X 100%) represents system energy losses as a percentage of NSI.

Staff has calculated a loss factor for the twelve months ending December 2007 of 5.34% of NSI. This is the line loss percentage that is being utilized by Shawn E. Lange in developing the loads used in Staff's fuel model.

Staff Expert: Alan J. Bax

8. Planned and Forced Outages

Planned and forced outages were normalized by using the six-year average of actual values taken from data supplied by KCPL.

Staff Expert: Leon C. Bender

B. Payroll, Payroll Related Benefits including 401K Benefits Costs and

1. Payroll Costs

Upon the consummation of the acquisition of the former Aquila regulated Missouri utilities, (MPS, L&P electric and L&P steam) approved by the Commission in Case No. EM-2007-0274, remaining employees of the former MPS, L&P and L&P Steam divisions became employees of KCPL. The transfer of the former Aquila employees was made at the close of the acquisition transaction July 14, 2008. The former Aquila entities now are providing utility services under the name KCP&L Greater Missouri Operations Company: GMO MPS, GMO L&P and GMO L&P Steam. Because all former Aquila employees providing service to the GMO MPS, GMO L&P and GMO L&P steam operations became part of the KCPL employee base, KCPL now has to allocate costs directly to KCPL service territory and the two

GMO operating entities, MPS and L&P. Additionally, L&P operations supplies utility services to electric and steam customers and L&P labor costs must be allocated between the electric and steam operations. Developing an accurate cost allocation methodology was critical in assuring that proper labor costs were being correctly assigned appropriately to the three separate operating entities, KCPL, GMO MPS and GMO L&P.

In its September 30, 2008 updated filing, the Company assigned costs based upon annualized levels in its original filing. Staff examined these calculations and compared them with test year labor amounts for KCPL, MPS and L&P. Staff also reviewed the estimated allocation factors developed by KCPL in the aforementioned acquisition case. In addition, Staff examined actual payroll costs charged to KCPL, MPS and L&P from the inception of the merger (July 14, 2008) through November, 2008. The actual charges made to the post-acquistion KCPL and GMO operations formed the basis of the allocation percentages used as a method to allocate base payroll costs to the respective KCPL, MPS and L&P entities.

Based on the other allocation amounts to the GPE entities, Staff concluded that the actual charged amounts were the best allocation of payroll between KCPL, MPS and L&P. Staff utilized actual charged amounts to the three operating entities, net of joint partners, Wolf Creek, and Jeffrey Energy Center charged payroll. The joint partners' costs are amounts charged to KCPL's other partners of the generating assets owned and operated by the Company, with the exception of Wolf Creek, a separate operating company 47% of which is owned by KCPL.

Staff annualized payroll costs in this case using actual employee levels as of the update period of September 30, 2008. Wages and salaries as of September 30, 2008 were applied to each individual employee to compute the total GPE and KCPL payroll costs on an annual basis.

Annualized payroll included differential and premium pay paid to KCPL employees based on union contracts.

As of September 30, 2008, KCPL's holding company, GPE, has labor costs that are to be annualized using current employee levels and current salaries. GPE provides common services such as accounting, tax consolidation, corporate legal and governance to GPE entities. The amount of GPE payroll that relates to KCPL and the GMO entities had to be determined in order to include those costs in the total payroll.

Through discussions with the Company, it was determined that 71 employees were part of the consolidation of operations transition work force and should be removed from the list of regular employees. Also removed were non-active employees on various types of extended leave. Temporary and intern employees were annualized based upon a three-year average of such employees. One GPE corporate employee who is a lobbyist for the corporation was not included in Staff's annualized payroll. The GPE employees were segregated for their allocation to regulated operations based on the allocation for 2007 of 69.03%. The amount of GPE annualized payroll as well as a three-year average of GPE overtime was allocated to KCPL and GMO MPS and L&P.

On December 16, 2008, GPE was restructured with all GPE and GPES employees becoming KCPL employees. Since this occurred outside the update period of September 30, 2008, used in this case, Staff has not yet determined the allocation process to be used for the true-up. There will be no GPE employees to allocate in the future, and Staff will have to examine the impacts of the GPE restructuring on the regulated operations of KCPL and GMO.

Overtime payroll for KCPL and overtime payroll billed to KCPL from the Wolf Creek generating facility were calculated based upon a three-year average. These amounts are specific to KCPL, MPS and L&P service territories and, therefore, it is not necessary to include the overtime as part of the allocation process for annualized payroll. The payroll overtime costs have been directly assigned to KCPL, MPS and L&P.

As the result of KCPL's operating agreements for generating facilities with several partners, it is necessary to assign costs to these partners and remove those payroll costs from the payroll annualization that is reflected in the revenue requirement calculations. This assignment of joint partner billings is necessary to ensure that payroll costs properly billed to the joint partners are not included in the KCPL payroll costs. The level of payroll billed by KCPL to its joint owners in the Iatan and LaCygne generating stations was also based upon a three-year average. Staff used the Company methodology to correctly allocate the reduction in payroll costs from the billing of joint partners, and these costs were removed net of the L&P portion of Iatan before the allocation of payroll to KCPL and GMO. The other payroll costs for partners are billed to The Empire District Electric Company, the other partner in Iatan and to Westar Energy Company, the 50% partner in the two LaCygne generating facilities.

The total annualized GPE and KCPL payroll costs allocated to KCPL also have to be assigned between operational and maintenance (O&M) expense and other expense. Typically the other expense amount relates to construction and other non-expense functions of the company. The construction amounts are assigned to the work orders for construction projects. The amounts that are included in the revenue requirement calculations for KCPL are the levels assigned to payroll expenses through the O&M expense ratios.

After allocation between expense and construction based on the test year expense factor, the adjustment for payroll was distributed by individual FERC account based upon the actual distribution for each of those accounts for 12-months ending December 31, 2007, the test year used in this case. Staff's accounting schedules reflect approximately eighty (80) adjustments by FERC account to reflect the adjustment required to restate the 2007 test year payroll to an annualized level as of September 30, 2008.

The following adjustments to the income statement reflect the following annualized payroll as of September 30, 2008. E-4.1, 5.3, 11.1, 12.1, 13.1, 19.1, 20.1, 21.3, 22.1, 23.1, 27.1, 30.1, 31.1, 32.1, 33.1, 40.1, 41.1, 42.1, 43.1, 44.1, 55.1, 56.1, 58.1, 59.1, 63.1, 64.1, 65.1, 66.1, 74.1, 75.2, 80.1, 81.1, 82.1, 83.1, 84.1, 86.1, 91.1, 92.1, 93.1, 94.1, 95.1, 102.1, 103.1, 104.1, 105.1, 106.1, 107.1, 108.1, 109.1, 110.1, 114.1, 115.1, 116.1, 117.1, 119.1, 121.1, 122.1, 123.1, 124.1, 128.1, 129.1, 130.1, 137.1, 147.1, 149.1, 153.3, 154.2, 158.1, 160.2, 164.2, 165.1, 172.1, 173.1, 174.1, 176.1, 177.1, 179.5, 180.1, 181.2, 182.1, 185.1.

Staff Expert: Keith A. Majors

2. Payroll Taxes

Payroll taxes were annualized by applying current payroll tax rates to each employee's annual level of payroll. To compute payroll taxes for overtime, interns, premium pay, and partner billings, an aggregate tax rate was applied based on the annualized payroll taxes for base payroll. Wolf Creek payroll has a separate aggregate payroll tax rate applied based on test year billed taxes. The payroll taxes follow the same allocation process used to allocate base payroll. Adjustments E-199.5, E-199.6, and E-160.3 to the Income Statement reflects the annualized payroll taxes based on payroll costs as of September 30, 2008.

Staff Expert: Keith A. Majors

3. Payroll Related Benefits

Staff annualized 401k expenses were calculated based upon the test year percentage match for KCPL applied to its share of total annualized payroll. In addition, the joint partner share of KCPL 401k expenses was removed from the annual level similar to the annualized payroll adjustment.

Medical costs were annualized based upon a calculation of six months ending September 30, 2008. This annualization reflects the increased payments to the employee VEBA, (Voluntary Employee Benefit Association) which is a trust fund that pays for employee medical costs. These increased payments were not reflected until April 2008, hence the six month calculation. Additional medical costs had to be removed for the former Aquila employees who were transferred as KCPL employees on July 14, 2008.

Other employee benefits were annualized based upon the twelve months ending September 30, 2008. An adjustment was necessary to the cost of miscellaneous employee benefits, account 926004 due to a change in accounting methodology by the Company. This adjustment results from the transfer of charges of employee benefit credits from the various health and benefit programs to this account. Staff also annualized other categories of health costs in the same manner which would reflect the aforementioned transfer of costs.

Adjustment E-165.13, 165.19, 165.20 to the Income Statement reflects the annualized payroll related benefits based on payroll costs as of September 30, 2008.

Staff Expert: Keith A. Majors

4. True-up of Payroll Costs

Staff will update the total payroll costs for the true-up in this case which is based on March 31, 2009. The same methodology used to annualize payroll as of September 30, 2008, will be used for the March 31, 2009 true-up.

Staff Expert: Keith A. Majors

5. FAS 87 and FAS 88 Pension Costs

The ER-2007-0291 Pension Stipulation also addressed the ratemaking treatment for annual pension cost under FAS 87 and pension settlement and curtailment accounting under FAS 88. The ER-2007-0291 Pension Stipulation affirms the agreement memorialized as part of the Regulatory Plan Stipulation and Agreement the Commission approved in Case No. EO-2005-0329 in July 2005. The ER-2007-0291 Pension Stipulation also clarifies the accounting for pension cost allocated to KCPL's joint partners in the Iatan and LaCygne generating stations, and addresses the ratemaking treatment for a curtailment or settlement recognized under FAS 88.

Unlike FAS 87, which allows for a delayed recognition in net periodic pension cost of certain unrecognized amounts, FAS 88 requires the immediate recognition of certain costs arising from settlements and curtailments of defined benefit plans. Without the deferred accounting treatment the Commission approved in Case No. ER-2007-0291, KCPL would have been required to recognize significant FAS 88 pension costs in 2007 as a result of KCPL removing a significant number of employees with accrued pension benefits from the pension plan. This significant cost was primarily a result of KCPL's Talent Assessment Program. When a former employee chooses a lump sum payment for his/her pension plan benefits, a settlement occurs under FAS 88.

In Case No. ER-2006-0314, the Commission approved the Nonunanimous Stipulation and Agreement Regarding Pension Issues (ER-2006-0314 Pension Stipulation) which first authorized the deferral of FAS 88 costs. For FAS 88 costs, this Stipulation and Agreement authorized the deferral and amortization of the FAS 88 deferral balance over five years beginning with rates established in Case No. ER 2007-0291 in January, 2008. The 2006 Pension Stipulation requires KCPL to make contributions to the pension fund annually in amounts sufficient to equal the annual level of FAS 88 pension costs included in the cost of service. Adjustment E-165.3 and E-165.7 in the Staff's accounting schedules represents the five-year amortization of FAS 88 pension costs.

Pension cost under FAS 87 is reflected in the Staff's accounting schedules in this case, Case No. ER 2009-0089, consistent with the ratemaking treatment agreed to in the Stipulation and Agreements approved in KCPL's Regulatory Plan case, Case No. EO-2005-0329, and KCPL's most recent rate case, Case No. ER-2007-0291. KCPL's rate base discussed previously in Section I includes the unrecovered balance of the prior Prepaid Pension Asset and the 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. Adjustments E-165.1, E-165.2, are the adjustments in Staff's accounting schedules to reflect FAS 87 pension costs based upon KCPL's 2008 actuarial valuation and amortization of the related regulatory asset over five years.

Staff Expert: Paul R. Harrison

6. FAS 106 – Other Post Employment Benefit Costs (OPEBs)

Other Post-Employment Benefit Costs (OPEBs) are those costs incurred by the Company to provide certain benefits to retirees such as medical and life insurance benefits. The Company must determine its OPEB expenses based on FAS 106 and Staff has provided sufficient costs in its revenue requirement calculation to reflect a proper level for these post-employment benefit costs.

Section 386.315, RSMo. 2000, requires that the Missouri Public Service Commission

> …not disallow or refuse to recognize the actual level of expenses the utility is required by Financial Accounting Standard 106 to record for post retirement employee benefits for all the utility's employees, including retirees, if the assumptions and estimates used by a public utility in determining the Financial Accounting Standard 106 expenses have been reviewed and approved by the

> commission, and such review and approved shall be based on sound actuarial principles.

Financial Accounting Standard 106 expenses typically include retiree medical, dental, vision and life insurance benefit costs. Section 386.315, RSMo requires a utility to "use an independent external funding mechanism that restricts disbursements only for qualified retiree benefits for the FAS 106 costs recognized in a utility's financial statements and that all the funds to be used for employee or retiree benefits."

KCPL is funding its annual FAS 106 costs. Staff adjustment E-165.6 adjusts KCPL's test year 2007 FAS 106 costs to a level equal to the amount determined by KCPL's outside actuary.

Staff's adjustment annualizes OPEB expense as calculated under Financial Accounting Standard No. 106, *Employers' Accounting for Postretirement Benefits Other than Pensions* FAS 106, for KCPL's employees. OPEB expense reflects KCPL's current liability to provide retiree medical payments to its current employees as well as its retired employees. Staff used the FAS 106 cost level as reflected in a letter to KCPL from KCPL's actuary, Towers Perrin, received in response to Staff Data Request No. 286. This letter provides the level of FAS 106 OPEB expense booked by the Company for the updated test year period ended September 30, 2008, and the re-measurement cost to shift from fiscal year to calendar year end.

In September 2006, the Financial Accounting Standards Board (FASB) issued Financial Accounting Standard No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans (FAS 158), which amends FAS 87 and FAS 106. FAS 158 require recognition of the overfunded or underfunded status of pension and other postretirement benefit plans on the balance sheet. These changes were effective for publicly-held entities for fiscal years ending after December 15, 2006. In addition, for fiscal years ending after December 15, 2006, the measurement date is required to be the Employers' fiscal year end.

Staff adjustment E-165.4 and E-165.5 adjusts KCPL's test year 2007 FAS 87 and 106 costs for the shift from fiscal year-end to calendar year-end.

Staff Expert: Paul R. Harrison

7. Supplemental Executive Retirement Plan (SERP) Expense

Included in Staff's revenue requirement recommendation is the test-year amount of recurring SERP payments made by KCPL to its former executive employees. A SERP is a pension compensation program which provides benefits to highly-compensated employees over and above the benefits provided under the regular pension plan. In essence, the SERP is an additional executive benefit because it provides benefits over and above what is provided under the regular – all employee pension plan. In the test year, KCPL made $168,140 in recurring annual SERP payments. This amount has remained the same since at least 2002 and this is the amount that Staff has included in its revenue requirement recommendation in this case as reflected in adjustment E165.12.

During the period 2000 through 2007 KCPL made some level of lump sum SERP payments in six of the eight years. However, such payments as made by KCPL do not meet the basic ratemaking requirement of being known and measurable and thus cannot be quantified accurately enough to be included in cost of service. KCPL does not make lump sum SERP payments on an annual basis as evidenced that no such payments were made in 2007, the test year and no payments were made in 2008. In addition, lump-sum SERP payments are not a known and recurring cost and the dollar amount of the lump sum SERP payments have so much volatility that there is no way to even get close to accurately measuring this payment through a typical ratemaking normalization adjustment.

Because of its unique nature and the fact that it represents an additional executive pension benefit over and above what is already provided in the regular pension plan, Staff treats SERP costs somewhat differently than normal employee pension costs. Staff's policy has been and continues to be that it will recommend SERP costs to be included in cost of service if they are not significant, reasonably provided for and able to be quantified under the known and measurable standard. KCPL's annual recurring SERP costs of $168,140 meet this test.

Staff Expert: Charles R. Hyneman

8. Severance Costs – Non-Talent Assessment

KCPL is proposing to recover a three-year average of non-talent assessment severance payments. This proposal is reflected in KCPL's adjustment 20b. Staff is opposed to severance costs that do not produce any customer benefit and are likely to have already been recovered in rates through regulatory lag. In adjustments E-153.1 and E-154.3, the Staff removed KCPL's 2007 test year severance payments.

These severance payments made by KCPL are not recurring costs that should be borne by regulated customers, the cost are expenditures that will not result in any payroll savings costs, and lack support that they will provide any benefit to KCPL or its customers, now or in the future. In addition, by seeking rate recovery of severance payments, KCPL ignores the fact that, until rates change, payroll expenses for the severed employee continue to be recovered in rates after the employee leaves the Company.

Staff Expert: Paul R. Harrison

9. Severance Costs – Talent Assessment

In Case No. ER-2007-0291 KCPL proposed the recovery in rates of what it referred to as "Talent Assessment" or "Skill Set Realignment" costs. These costs were primarily severance payments for employees who were terminated or who decided to leave KCPL. The total cost of the severance program was approximately $9.6 million for the termination of 119 KCPL employees. The Missouri jurisdictional portion of those costs, as allocated by KCPL, was $4,840,517.

In KCPL's last rate case the Staff opposed rate recovery of these severance payments; however, the Commission, in its Report and Order in that case, Case No. ER-2007-0291, found this issue in KCPL's favor based on KCPL witness' testimony that this program is and will be beneficial to KCPL's customers. The Commission concluded that the Talent Assessment severance costs should be recognized in cost of service, and ordered the costs be deferred and amortized to expense over five (5) years commencing January 2007. The annual amortization of this deferral is $968,000; however, Staff has not made any adjustment to reflect this amortization in this case because during its audit in this case Staff found that the basis for the Commission's allowance of rate recovery of these severance costs no longer exists.

In its Report and Order in Case No. ER-2007-0291 at page 53 the Commission explains the basis for its decision to allow direct rate recovery of KCPL's Talent Assessment costs in that case as follows:

> …Common sense dictates that a company that is run more efficiently makes more money, at least in part because a higher level of efficiency results in happier customers. Indeed, the record is replete with evidence that KCPL's customer service is excellent. What is more, KCPL's ranking among Midwestern public utilities rose from eighth to fourth in 2006, according to a J.D. Powers and Associates survey, with those rankings measuring such components as power quality and reliability and customer service.

The Staff has found that KCPL's Missouri residential customers are significantly less happy with KCPL in 2008 then they were in 2007. As related in the Post-Merger Service Quality section of this report the number of KCPL residential customer complaints has increased substantially from 2007 to 2008, from 217 to 320. In addition to the increased unhappiness of

KCPL's residential customers, according to the JD Powers and Associates survey for business customers for 2008, KCPL's ranking and scores have deteriorated significantly.

In the J.D. Powers and Associates Business Customer Study for 2007, released in March 2007, KCPL's score was 725 as compared to Aquila's 694 and the Midwest average of 670. However, in the J.D. Powers and Associates Business Customer Study for 2008, released in February 2008, KCPL's score declined to from 725 to 704 while Aquila's score increased from 694 to 719 during this same period. The significant decrease in KCPL's business customer satisfaction is especially noteworthy, and of increased concern, because it occurred in a time period when business customer satisfaction with electric utility providers had reached record high levels across the nation, as noted in the JD Powers & Associates press release announcing the results of its survey. In a just-released 2009 Electric Utility Business Customer Satisfaction Study, KCPL's index score dropped from 704 in 2008 to 632 in 2009.

However, as noted in the schedules of Staff witness Lisa Kremer in the Post-Merger Service Quality section of this report, there are indications that KCPL's customer service quality has decreased from 2007 to 2008. KCPL's average number of customer complaints to the Missouri Public Service Commission averaged 217 for the years 2004 through 2006. In 2007, the number remained steady at 217, but in 2008, customer complaints increased 47 percent to 320.

As ordered by the Commission Order in Case No. ER-2007-0291, KCPL deferred Talent Assessment Severance Program expenses (severance, outplacement, payroll taxes, etc.) as a regulatory "asset" and began to amortize this asset to expense over five (5) years starting in January 2008, when rates from the 2007 rate case went into effect.

By the time new rates from this case are anticipated to be in effect August 200. KCPL will have directly recovered through current rates approximately thirty-two (32) percent of the $4.8 million deferral or $1.5 million (January 2008 through July 2009 is nineteen (19) months divided by the sixty (60) month deferral period equals 31.67%). KCPL's regulated customers will have directly paid at least one-third (1/3) of the total costs of the Talent Assessment Program.

The Staff recommends that the Commission find, based on the above described evidence, that KCPL's cost of severing the 119 employees, referred to as the cost of the Talent Assessment Program, did not result in the expected customer benefit and, therefore, not include the $968,000 annual amortization of the 5-year deferral as an adjustment to increase KCPL's revenue requirement in this case. In Staff's view, KCPL's rate recovery of approximately one-third (1/3) of the cost of the talent assessment program is more than adequate recovery of any actual benefits customers may have obtained from KCPL's Talent Assessment Program.

Staff Expert: Charles R. Hyneman

10. Short Term Annual Incentive Compensation

KCPL has three separate, short term annual incentive compensation programs for executive, management, and union classifications of employees. These programs are designed to grant cash awards of various amounts calculated from designated metrics for each year. The timing of the payout for amounts accrued during the year under each program is during the first quarter of the following calendar year. The three incentive compensation programs are: 1.) The Rewards program, reserved for bargaining employees; 2.) The Valuelink program, reserved for non-executive GPE and non-union KCPL employees; and 3. The Annual Executive Incentive Plan, reserved for senior GPE and KCPL management employees.

The incentive plans have benchmarks that identify targets that GPE and KCPL are expected to achieve before any cash payouts are given to employees. These targets are established each year of the incentive plan and communicated to the employees early enough so that the employees have sufficient opportunity to reasonably achieve the benchmarks.

The Rewards program covers bargaining unit (union) employees from IBEW Local 1464, 412, and 613 Unions.** ____

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The Valuelink program covers non-executive GPE and non-union KCPL employees. ** ____

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** The Commission has historically disallowed incentive compensation based upon corporate financial measures as there is no obvious tangible benefit to ratepayers, specifically in KCPL Case No.'s ER-2006-0314 and ER-2007-0291. The KCPL Scorecard for the Valuelink plan has no such financial metrics. The 20% discretionary portion of this calculation was also disallowed by the Commission in Case No. ER-2007-0291. This portion of the calculation has no specific target to achieve.

The third short term annual incentive plan is the Annual Executive Incentive Plan designed for senior GPE and KCPL management.**

**

For the test year 2007 award paid in the first quarter of 2008, the EPS threshold was not met for any of the aforementioned short-term incentive plans. However, based upon the discretion of management, it was determined that the Company would pay an award amount to its employees although the Company did not meet the threshold for granting short term incentive compensation. The amount given to employees under the Rewards Program was $250 and Valuelink Employees were given 1.5% to 5% of base pay, depending on salary band. Duly noted in the Company memorandum detailing this payout was the unique, one-time nature of this payout and that employees should not consider this a recurring event.

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** Therefore, Staff has removed the entire test year short term incentive compensation.

Staff is recommending that the test year cost of short-term incentive compensation be excluded from the cost of service based upon the following rationale:

1. The test year short term incentive compensation did not adhere to any of the program documents which informed participants that no bonus would be awarded if the EPS threshold was not met.

2. Awarding incentive compensation to employees when the threshold goal is not met is contrary to the theory of incentive compensation.

3. ** ____

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The Power Marketing Incentive Plan was discontinued after 2007 and associated costs were removed from the cost of service.

Adjustments E-74.2, 4.2, 80.2, 110.2, 128.3, 137.4, and153.6 to the Income Statement are to remove costs relating the short term incentive compensation for the test year 2007.

Staff Expert: Keith A. Majors

11. Long Term Incentive Compensation

The Company's Long Term Incentive Compensation program is designed to award KCPL and GPE Executives two types of stock:

1) Restricted Stock is stock which must be held for a specific period of time before it can be transferred or sold.
2) Performance Shares are shares of stock awarded based upon the achievement of goals which are entirely or primarily the achievement of EPS and shareholder return.

Staff is recommending that the test year cost of long term equity compensation be excluded from the cost of service on the following rationale:

1) Equity compensation is awarded based upon goals which are entirely or primarily tied to EPS and total shareholder return, beneficial to shareholders, not customers.
2) Unlike other forms of employee compensation, equity compensation does not require a cash outlay by KCPL. KCPL is requesting cash recovery

for ** __________ **(total Company) in equity compensation which will never require a cash outlay by KCPL.

3) The shares of GPE stock held by GPE and KCPL executive management will earn a return based upon the return on equity collected from ratepayers through rates. If KCPL had issued long term debt in lieu of issuing additional equity to executive management, the cost of capital required from customers would be lower.

This is the same position Staff took on long term incentive compensation in Case Nos. ER-2006-0314 and ER-2007-0291. Adjustment E-153.5 to the Income Statement is to remove costs relating to the long term incentive compensation for the test year 2007.

C. Maintenance Normalization Adjustments

Maintenance expense is the cost of maintenance chargeable to the various operating expense and clearing accounts. It includes labor, materials, overheads, and any other expenses incurred in maintenance of the Company's assets - including power plants, the transmission and distribution network of the electric system, and the general plant. Specific types of maintenance work tied to specific classes of plant are listed in functional maintenance expense accounts in the FERC Uniform System of Accounts (“USOA”) for the various types of utilities. Maintenance expense normally consists of the costs of the following activities:

- Direct field supervision of maintenance.
- Inspecting, testing and reporting on condition of plant, specifically to determine the need for repairs and replacements.
- Work performed with the intent to prevent failure, restore serviceability or maintain the expected life of the plant.
- Testing for, locating, and clearing trouble.
- Installing, maintaining, and removing temporary facilities to prevent interruptions.
- Replacing or adding minor items of plant, which do not constitute a retirement unit.

Staff analyzed maintenance costs from 2001 through 2008 by functional area for production, transmission, distribution and by FERC account. Staff separated maintenance between labor and non-labor costs. Since labor costs are specifically addressed as a component in the cost of service analysis, labor costs were segregated from the non-labor costs to perform the review of maintenance costs. Staff annualized payroll reflecting the price increases for labor that generally occurs each year. A detailed staff position related to payroll is located under the heading *Payroll, Payroll Related Benefits* in this report.

Several steps were taken to analyze the maintenance data. They included examining the non-labor maintenance amounts to identify any characteristics of the maintenance dollars such as trends or fluctuations from one period to another. Another approach used by Staff, was to compare functional averages which included using a 2-year average through a 7-year average to determine if there were fluctuations with each functional area. These steps were also compared to the 2007 Test Year. Staff reviewed the data as detailed above to establish a maintenance level that will result in an annual level of the Company's future maintenance costs. Staff made a decision to use the 2007 test year account balances for future maintenance costs. This decision was based on data provided by the Company, initiatives implemented by the Company to reduce maintenance costs, and a Commission rule related to preventative maintenance with Transmission and Distribution.

In the Company's testimony, several maintenance initiatives were identified that would result in a reduction in maintenance costs. The programs included are:

- Electric Power Research Institute Plant Reliability Optimization (EPRI-PRO)
- Planning and Scheduling Tool Assistant (PASTA)
- Smart Signal
- Plant Improvements
- Upgrades and retrofit projects to existing stations
- Operations and Maintenance Programs

- Accelerated Corrosion Program

These programs should have a positive effect on the Company's maintenance program and result in savings over time.

Staff member Daniel I. Beck is providing information regarding the vegetation management and infrastructure inspection programs KCPL implemented for the new Commission rules. In essence, the unadjusted test year amounts for maintenance are higher due to the increase in costs associated with vegetation management and infrastructure inspection. Implementation of the vegetation management program and inspection of the distribution and transmission system will result in higher costs that have been reflected as separate adjustments in this case and should not also be included in the maintenance adjustments. To do so would result in those costs being included in the case twice.

Staff Expert: Karen Herrington

D. Depreciation - Clearing

During the test year, the Company included depreciation for transportation equipment that was charged to expense through a clearing account. Staff made an adjustment to the depreciation amount. Adjustment E-182.2

Staff Expert: Karen Herrington

E. Other Non-Labor Adjustments

1. Hawthorn No. 5 Subrogation Proceeds

In 1999, Babcock & Wilcox (B&W) entered into an engineering, procurement and construction agreement with KCPL for the construction of Hawthorn Unit 5 boiler island (Agreement). The Agreement required B&W to install a selective catalytic reduction system (SCR) at Hawthorn Unit 5. Under the Agreement, as amended, B&W guaranteed certain performance standards, including an ammonia slip test. After the SCR was placed in service in 2001 it failed the ammonia slip test.

In 2002 both KCPL and B&W tried to resolve the issues by B&W doing additional work. In 2004 B&W and KCPL entered in to a Memorandum of Understanding (MOU), and revised downward the ammonia slip test standards. B&W subsequently failed to meet the lowered standards. At this point KCPL decided to seek liquidated damages from B&W based on the difference between the costs KCPL would incur if the standards were met and what costs KCPL incurred because the standards were not met.

Because of B&W's failure to meet the ammonia slip test standards, KCPL experienced increased replacements of catalysts, increased usage of ammonia, plus additional cleaning and maintenance expense.

In 2007 KCPL received a settlement from B&W. All litigation and settlement discussions were handled in-house by KCPL attorneys. The increased costs for the ammonia slip tests, more frequent replacements of catalysts, and increased cleaning and maintenance expense continue to exist today. KCPL has and is experiencing higher costs and passing them to its customers, but is passing on all of these settlement proceeds to its shareholders.

Staff's position is that KCPL's customers should receive the benefit of the settlement with B&W since they paid the costs KCPL incurred because of the substandard performance of the plant. All the increased costs to KCPL were and are currently being paid by KCPL customers in utility rates. These costs include the salaries and benefits, office space, and all employee-related costs of KCPL's attorneys and employees who worked on this dispute between KCPL and B&W. It is Staff's position that since the capitalized cost to plant in service did not meet the contract specifications, the amount of plant on KCPL's books and records is overstated and should be reduced at least by the amount of the settlement agreement. However, to avoid the same FERC Uniform System of Accounts booking issues KCPL raised in Case No. ER-2006-0314, Staff has reflected the test year receipts of the B&W settlement proceeds as a decrease to Hawthorn V's plant reserve accounts. The effect of this adjustment is to reduce KCPL's rate base by the Missouri jurisdictional portion of the B&W settlement proceeds. Staff also reduced depreciation expense by the Missouri jurisdictional portion of this B&W settlement amount.

2. Hawthorn V Transformer

In August 2005, the generator step-up transformer (GSU) on KCPL's Hawthorn unit No. 5's failed. A spare GSU was installed in September 2005. During June 2006, a new GSU transformer was installed. KCPL sued the contractors and subcontractors that it claimed were responsible for the GSU failure. The case settled at the end of 2007, and was finalized in 2008. While KCPL has made no adjustment in its books and records to provide any benefit of this settlement to its customers, it is Staff's position that KCPL's customers should receive the benefit of the settlement since they are the ones who paid the costs of the substandard plant performance.

All the increased costs to KCPL of the operation of the Hawthorne unit No. 5 caused by the GSU failure were paid by KCPL customers in utility rates. These costs include the salaries and benefits, office space, and all employee-related costs of KCPL's attorneys and employees who worked on KCPL's dispute with the contractors and subcontractors, increased maintenance, fuel and purchased power expense and increased expenses that were capitalized to the new plant. As described above for the Hawthorn SCR performance issue, Staff is proposing to decrease the depreciation reserve for the Hawthorn V transformer account, which will have the effect of reducing KCPL's rate base.

3. Spearville Availability Credit

KCPL's Spearville Wind Energy Facility was placed in service during the second half of 2006. A portion of the cost of this plant that is included in KCPL's rate base is the cost of a two-year warranty where the contractor guaranteed KCPL 95 percent availability of the wind energy. At the end of the two-year warranty period KCPL received a warranty payment for the portion of the two years when the wind energy did not meet the 95 percent availability standards. While, like the Hawthorn SCR and GSU and GSU settlement proceeds, KCPL made no adjustment to its books and records to provide any benefit of this warranty payment to its customers, it is Staff's position that because KCPL's customers paid for the cost of the warranty that is in its rate base and is generating a return, including a profit to its shareholders and depreciation expense recovery, KCPL's shareholders should receive the benefit of the warranty payment. For this warranty payment Staff is amortizing the amount of the warranty payment over a five-year period and including the resulting annual amount as a reduction to KCPL's cost of service and, therefore, revenue requirement. This position is based on the fact that the cost of the warranty was not paid by KCPL's shareholders, but KCPL's customers and KCPL's customers continue to pay for that warranty as the cost of the plant is included in rate base and is being depreciated.

Staff Expert: Charles R. Hyneman

3. Employee Relocation Expense

In its review of KCPL's books and records, Staff noticed that KCPL's employee relocation expense has increased significantly over the last few years. An increase in this cost is consistent with KCPL's high employee turnover rate from its talent assessment program. In Staff Data Request No. 141.2, Staff asked the following:

1. In 2000 through 2003 relocation expense was in the range of $30,000 to $40,000. In 2004 through 2007 this range increased to $390,000 - $400,000. Please provide all reasons for this significant increase, including changes in policies.
2. During the period 2000 through 2005 KCPL, the number of employees for whom KCPL paid relocation expenses ranged from 8 to 16. In 2006 KCPL paid relocation expenses for 25 employees and in 2007 KCPL paid relocation expenses for 30 employees.
3. Please provide all reasons for this significant increase including changes in policies and procedures.

In its response to this data request KCPL stated:

> The increase in costs and employees paid relocation cannot be attributed to any single reason. Our hiring was up somewhat due to ramp-up of the construction build, replacing some of the people who left as a result of the Talent Assessment process, and building capabilities in key areas such as in the energy management system group. Most impactful is that as we recruit candidates for key positions (such as the senior leadership team, certain foremen, managers and supervisors, and attorneys) and hard-to-fill positions (such as journeymen, engineers, certain technician classifications) in a market that is increasingly competitive and exacerbated by an aging population, it is necessary to broaden our search outside of the Kansas City metropolitan area and which requires relocation as part of a candidate's offer package.

This response indicates that a portion of KCPL's employee relocation expense is driven by its Talent Assessment Program. The Talent Assessment Program was a major program KCPL instituted in 2006 to terminate employees who were not able or willing to meet KCPL's employment standards. Approximately 119 employees were terminated under this program and KCPL incurred costs of approximately $9.5 million, primarily severance costs. KCPL is currently recovering the Missouri jurisdictional portion of this amount in rates through a five-year amortization which was approved by the Commission in Case No. ER-2007-0291.

Because KCPL's relocation costs over the past several years are caused by nonrecurring events such as the Talent Assessment Program and the buildup of its construction program, it would not be appropriate to use these costs in the calculation of an expense level that is supposed to be representative of KCPL's actual ongoing level of employee relocation expense.

In response to Staff Data Request No. 143.3, KCPL stated:

> …that after management reviewed the proposal from Cartus with the recommended cost savings, Cartus was selected as KCPL's relocation vendor and enacted a KCPL 2008 relocation program. With the considerable research of programs offered by Cartus and their interaction with other companies; KCPL made the decision to adopt the proposal for a much more competitive and contemporary program.

During calendar year 2008, Cartus relocated nine KCPL employees at a total Company cost of $150,345. Staff used the average cost of $16,705 that the Company paid Cartus to move each employee during calendar year 2008 and multiplied that number by twelve, the mid-point number of employees that KCPL paid to relocate employees between calendar years 2000 through 2005, the period prior to the nonrecurring events incurrence that was mentioned above. Using this analysis, Staff's adjusted total company employee relocation costs were $200,460 ($16,705 x 12). As indicated in Staff Data Request No. 141.2, historically for KCPL this $200,460 level is still very high and Staff will be looking closely at this issue in the true-up period and KCPL's next rate case to see if KCPL can bring this cost down to roughly the pre-2003 relocation expense levels. (Staff adjustment E-157.3 adjusts KCPL's test year 2007 relocation costs).

Staff Expert: Paul R. Harrison

2. Lobbying Expenses

In adjustment E-75.1, E-153.2, E-154.1 and E-165.8, Staff removed the annual payroll and estimated benefits cost of KCPL's Washington D.C. lobbyist from the Company's cost of service expenses. Staff considers this expense, as well as the expenses of all KCPL employees who engage in lobbying activities, to be required to be charged to USOA, Account 426.4, Expenditures for Certain Civic, Political and Related Activities. Lobbying costs should not be included in the cost of service because they do not provide any direct benefit to KCPL's customers. Lobbying costs are related to expenditures of the Company to influence public opinion with respect to election or appointment of public officials, legislation, or ordinances. Staff's position on lobbying expenses is that all lobbying activities should be recorded below-the-line in USOA Account 426.4. These costs include dollars paid to external lobbyists (outside vendors and contractors) and internal lobbyists.

FERC Account 426.4 is defined as follows:

> This account shall include expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances (either with respect to the possible adoption of new referenda, legislation, or ordinances or repeal or modification of existing referenda, legislation or ordinances) or approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials, but shall not include such expenditures which are directly related to appearances before regulatory or other governmental bodies in connection with reporting utility's existing or proposed operations.

Staff Expert: Paul R. Harrison

3. Lease Expenses

Lease costs are those costs incurred by KCPL for the leasing of its corporate headquarters. Staff examined these costs and found that in 2007, lease payments were reduced. Staff made an adjustment to reflect these lower costs in rates to be set in this proceeding.

Staff submitted Staff Data Request No. 155 asking KCPL to reconcile the difference between the Company’s responses to Staff Data Request No, 16, total 2007 lease expense and

Staff Data Request No. 13, KCPL's 2007 general ledger's USOA Account Number 931 lease expenses. The Company's response to Staff Data Request No. 13 indicates that KCPL's 2007 cost of service included a monthly leasehold expense of $407,435 for the 1201 Walnut building and parking area for the first six months of 2007 and then the monthly leasehold expense decreased to $321,175 on July 1, 2007. Staff annualized KCPL's leasehold expense by multiplying the monthly leasehold expense of $321,175 over a 12-month period. This annualization resulted in a decrease in the level of this expense of $514,103. (Staff adjustment E-180.1 adjusts KCPL's test year 2007 for leasehold expenses.)

Staff Expert: Paul R. Harrison

4. Meals and Entertainment Expense

In Case No. ER-2007-0291, Staff removed KCPL's test year charges to resource code 378, Meals and Entertainment expense. These charges consist of the cost of local meals (meals consumed in the Kansas City, Missouri area) that KCPL's employees determine to be "business meals" that should be charged to KCPL and thus to KCPL's regulated utility customers.

Staff made this adjustment for two primary reasons. The first is that there is a general presumption that KCPL's employees should pay for the meals they consume in the local area, as opposed to meals incurred during travel on official business. While there may be times when a KCPL employee may be required to attend a function and incur meal expense he/she would not normally incur, those occasions should be rare.

The second reason for Staff removing the cost of local business meals is that in the last two KCPL rate cases, Nos. ER-2006-0314 and ER-2007-0291, Staff noted several discrepancies and improper charges by KCPL's officers in costs charged to KCPL through its expense report process. These problems were also noted by KCPL's internal audit employees in the Great Plains Energy Officers and Directors Expense Review Audit Report. Staff had concerns about the local business meal expenses in both of KCPL's previous rate cases and disallowed these expenses in KCPL's last case. This disallowance was necessary because of the discrepancies noted during its review of the expense reports and the problems identified by KCPL's internal audit employees.

During our review of officer expense reports for this case, Staff noted that KCPL continues to have problems with excessive charges for meals being made by its employees on their expense reports Staff's general position is that meals consumed by KCPL in the Kansas City area should be a personal expense. KCPL is excessive charging local meals to cost of service and not even complying with its own expense report policies.

The KCPL internal audit employees conducted another review of GPE officer and director's expense reports in April 2008. During that review they noted that:

> …the documentation of business expenses is generally not in compliance with nor as robust as the documentation requirements prescribed by the Policy and the IRS. The lack of clear and concise documentation created some difficulty in identifying the business purpose of the expense. We recommend that the individuals preparing the expense reports and those approving the expense reports ensure compliance with the documentation requirements of the Policy.

In conclusion, Staff has identified problems with the charges being made by KCPL officers and being included in KCPL's cost of service in their last two rate cases and these problems continue in this case. The Company's own internal auditors have identified that the documentation of business expenses is not in compliance with KCPL's own policies. (Staff adjustment E-124.1 and E-154.5 adjusts KCPL's test year 2007 Meals and Entertainment costs)

Staff Expert: Paul R. Harrison

5. Nuclear Decommissioning

In its Report and Order in Case No. ER-2006-0314, the Commission ordered the following:

> 1) KCPL's annual Missouri retail jurisdictional decommissioning cost accrual shall be $1,281,264, commencing January 2007

> and KCPL's decommissioning trust fund payments shall be at that annual level;
>
> 2) Decommissioning cost accruals, as a consequence of "1)," will continue to be included in KCPL's cost of service and will continue to be included in KCPL's rates for ratemaking purposes;

After reviewing the Company work papers, Staff found the test year reflected the amount ordered by the Commission and that therefore no adjustment was necessary to the decommissioning cost accrual in this case.

Staff Expert: Karen Herrington

<u>6. DOE Refund of Nuclear Fuel Overcharges</u>

During the period of 1986 through 1993, the United States Department of Energy overcharged KCPL for uranium enrichment services. KCPL filed a lawsuit resulting in a settlement of $427,150. The Commission ruled in KCPL's last rate case, Case No. ER-2007-0291, the following:

> The Department of Energy Nuclear Fuel Overcharge Refunds for 1986 through 1993 KCPL received during the test year in this case should not be included in KCPL's cost of service for setting KCPL's rates.

Based on the Commission ruling, Staff issued an adjustment to mirror Company's adjustment issued in this case. Adjustment number E-28.

Staff Expert: Karen Herrington

<u>7. Property Tax Expense</u>

Each year KCPL is billed by each of the taxing authorities that have jurisdiction over the Company's property. Tax bills for the year are based (assessed) on the property KCPL owns on the first day of that calendar year, and only on January 1st of each year. The property taxes assessed on January 1 of each year are typically not due to the taxing authorities until December 31 of that year, and in the state of Kansas, part of the year's property taxes are not due until late in the first quarter of the following year. The test year being used in this case is the 12-month period ending December 31, 2007, updated through September, 2008. Since the update period in this case is September 30, 2008, Staff has determined the annualized property taxes based on the property KCPL had in-service on January 1, 2008. Staff applied a property tax ratio based on actual 2007 property tax payments to January 1, 2007 plant. This ratio of property taxes when applied to the January 1, 2008 plant balance provides the amount of property taxes expected to be paid for 2008. Since the actual 2008 property taxes owned by the Company have been paid as of December 31, 2008, Staff plans on updating its property taxes for the true-up which will be through March 31, 2009. Because the update in this case is September 30, 2008 property tax expenses were annualized as of the January 1, 2008 date. This calculation is an estimate of what the total 2008 property tax expense will be. Both Staff and the Company have typically accomplished this by looking to the tax rate paid for the previous year, and then applying it to the property owned at the start of the current year. For the current rate case, Staff has obtained from KCPL the total amount of taxable property owned on January 1, 2008, and then applied to it the tax rate assessed to the Company in 2007. The property tax rate assessed in 2007 is calculated by dividing the total amount of property tax paid by the Company by the total cost of the taxable property owned on January 1, 2007. Any required payments in lieu of taxes ("PILOTs") applicable to non-taxable property were added to the total estimated tax for 2008. Staff believes that the property tax expense arrived in this manner is the best available information, since it relies on the actual January 1, 2008 balance of KCPL's property, and uses the most recent, known tax rate (2007), without attempting to estimate any change in the rate of taxation for 2008 that is not known as of the update period September 30, 2008. Even though the 2008 property tax payments are known at the end of the year and at the time of this filing, since there is a true-up scheduled in this case, Staff felt it was appropriate to include the annualized property taxes through the update period, September 30, 2008. The property taxes will be trued-up during that phase of the case.

Staff adjusted test year property tax expense in order to include in rates the annualized level of 2008 property taxes. Staff's approach is consistent with that taken previously and has received several favorable rulings from the Commission in prior cases, most recently in KCPL 2006 rate case. In its Report and Order issued in Case No. ER-2006-0314 the Commission stated the following:

> Staff recommends that the Commission calculate property tax expense by multiplying the January 1, 2006 plant-in-service balance by the ratio of the January 1, 2005 plant-in-service balance to the amount of property taxes paid in 2005. KCPL wants the property tax cost of service updated to include 2006 assessments and levies. The Commission finds that the competent and substantial evidence supports Staff's position, and finds this issue in favor of Staff.

Based on the methodology addressed earlier, Staff issued an adjustment to include an annualized amount for property taxes. Adjustment E-198 reflects the annualized levels.

Staff Expert: Karen Herrington

<u>8. Bad Debt Expense</u>

Bad debt expense is the portion of retail revenues KCPL 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 to a third party collection agency for recovery. If KCPL is subsequently able to successfully collect some portion of previously written off delinquent amounts owed then those amounts collected reduce the actual write-offs. This results in the net write-off which is used to determine the annualized level of bad debt expense. Staff calculated the annualized bad debt expense by examining the billed revenues, net of gross receipt taxes for the twelve months period ending March 31, 2008, and actual 12-month history of billed revenues that were never collected (actual net write-offs) for the twelve months ending September 30, 2008. From this information a bad debt ratio was derived, which was then applied to Staff's annualized level of retail revenues to obtain the annualized level of bad debt expense. The apparent lag time between the net retail sales and actual net write-offs in Staff's calculation is consistent with KCPL's position on how bad debt write-offs are accounted. The Company asserts that it takes approximately six months for a customer's unpaid bill to be written off after the customer receives service. Staff's adjustment for bad debt expense adjusts the test year results to reflect a level of bad debt expense that is consistent with Staff's annualized level of retail revenue. This is adjustment E-131.1.

Staff Expert: Kofi Agyenim Boateng

9. Advertising Expense

In forming its recommendation of the allowable level of advertising expense, Staff relied on the principles the Commission followed as a result of the 1986 Kansas City Power & Light rate case, (Case No. EO-2005-0329 beginning with the 2006 rate case, Case No. ER-2006-0314). In Re: Kansas City Power and Light Company, 28 MO P.S.C. (N.S.) 228 (1986) (KCPL), 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 are:

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

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

3. <u>Promotional</u>: advertising used to encourage or promote the use of electricity;

4. <u>Institutional</u>: advertising used to improve the company's public image;

5. <u>Political</u>: 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 No. EO-85-185, 28 Mo.P.S.C. (N.S.) 228, 269-271 (April 23, 1986)).

In response to data requests, KCPL provided a list of all advertising costs with the associated description of the costs. Staff held two meetings with KCPL to review these costs and reviewed certain large dollar advertisement programs. The purpose of Staff's review of KCPL's advertising costs was to ensure that only advertising costs for programs necessary for the provision of safe and adequate utility service are included in KCPL's cost of service. For example, all costs for safety advertising and indirectly related to safety advertising were included as well as other costs necessary for KCPL to communicate with its customers on utility matters.

Staff determined that some of the test year advertising costs was related to KCPL's Demand Side Management (DSM) program and should have been charged to that account. Staff removed test year expenses incurred by KCPL for advertising programs that are appropriately classified as institutional image in nature.

Advertising costs that informed KCPL's customers of ways to use energy more efficiently were transferred from advertising expense category to KCPL's DSM cost deferrals and treated consistent with the DSM cost recoveries. Staff transferred approximately $525,000 of KCPL total advertising expenses from the income statement to the DSM deferral. This amount on a Missouri jurisdictional basis is approximately $280,000.

In its direct filing in this case KCPL did not make any adjustment to remove any advertising costs. Upon questioning from Staff, KCPL did propose to remove approximately $420,000 of image and institutional advertising. Based on Staff's review it removed an additional $460,000 in advertising costs related to television commercials designed to promote KCPL's image in the community. Staff also removed some costs related to outside consultants who designed these advertisements. Staff focused on campaigns, not individual ads, which is consistent with the Commission's discussion on the topic as stated in its most recent rate case order, the AmerenUE Report and Order in ER-2008-0318.

10. Dues and Donations

Staff reviewed the list of membership dues paid and donations made to various organizations, that KCPL charged to its' utility accounts during the test year. Consistent with Staff policy for many years, Staff included all dues payments made by KCPL to each area's Chamber of Commerce, and removed the other dues as costs not necessary in the provision of utility service. This adjustment was made to KCPL account 930.2. In addition to this adjustment, Staff removed costs booked to account 926 in the 2007 test year that were made for amusement park tickets, sporting events, and retiree luncheons. Staff considers these expenses to be personal in nature and thus, not included in a utility's cost of service.

Staff Expert: Bret Prenger

11. Removal of Gross Receipts Taxes from Test Year Revenues

The amounts received from customer payments and recorded as revenues during the test year included gross receipt taxes (GRTs) imposed by a taxing authority for which KCPL is obligated to charge customers on their utility bills. After KCPL collects these taxes from its customers, the Company periodically remits these amounts to the appropriate taxing authority. In this regard, to accurately account for the Company's actual test year retail revenues – it is necessary to remove GRTs from the amounts recorded as 2007 revenues – while at the same time removing the corresponding remittances to the taxing authority as a charge to expense. In effect, GRTs will have no impact on the Company's final revenue requirement amount. Staff's adjustments remove GRTs from test year revenues and expenses. The adjustments are Rev-2.2, Rev-16.2 and E-201.1.

Staff Expert: Kofi Agyenim Boateng

12. Debit/Credit Card Acceptance Program

In February 2007, KCPL implemented a Credit/Debit Card payment program designed to help and offer utility ratepayers a simplified, quick and convenient way to pay their bills, and to manage their accounts electronically. The program is offered by KCPL in an agreement with Western Union through its SpeedPay, which act as third party facilitators for the processing of payments to KCPL. When payment is made by a customer through the credit or debit card system, KCPL will receive payment from Western Union. Payment options available to customers through the program include the Interactive Voice Response System ("IVR") and KCPL's website, which are all one time payments and what the Company terms recurring card payment option available through enrollment on its website. The costs for providing this service are absorbed by KCPL and later built in rates; therefore, customers who use this payment option are not charged any direct transaction fees. Since the introduction of the program in February 2007, customer participation every month has been gradually increasing. This is projected to increase into the future as more customers become aware of the program. Thus, resulting in the decline of per unit transaction cost to KCPL.

Staff has included an annualized amount associated with the credit and debit card program in its cost of service prepared for KCPL based upon the total cards level and per unit transaction cost as of the end of the update period, September 30, 2008. This adjustment is represented in Staff's Accounting Schedules as E-130.3.

Staff Expert: Kofi Agyenim Boateng

13. KCPL Receivables Bank Fees

KCPL sells its accounts receivable, as described in Section 2 of the Direct Testimony of KCPL Witness Michael W. Cline in Case No. ER-2009-0089. The process is as follows:

- KCPL sells all of its receivables daily at a discount and on a non-recourse basis to Kansas City Receivables Corporation ("KCREC").
- KCREC gives a promissory note to KCPL for the amount of the discounted receivables purchased.
- KCREC sells an undivided interest in the receivables to a bank conduit (Victory Receivables Corp.).
- The bank conduit issues A-1/P-1 Commercial Paper to fund the purchase of the receivables from KCPL.
- The bank conduit advances funds to KCREC, which uses the funds to pay down the promissory note given to KCPL.
- KCREC pays KCPL a collection fee to collect the receivables monthly.
- KCREC pays Victory the Commercial Paper fees plus a program fee monthly.
- KCREC pays KCPL interest due on the promissory note monthly.

Staff included an annualized level of bank fees paid by KCPL to KCREC in adjustment E-128, schedule 9. Staff reflected the benefit of selling the accounts receivable as a reduction in the revenue lag in the cash working capital amount determined in this case. The selling of accounts receivable results in the Company collecting revenues on an accelerated basis from lending institution. The adjustment for bank fees relate to the costs of this program. The benefit to the Company is that it receives enhancement to its cash management. For rate making purposes this enhancement is reflected in the acceleration of the collection process identified through a shorter revenue lag in the CWC schedule than otherwise would have occurred absent the sale of the accounts receivables.

Staff Expert: Karen Herrington

14. Miscellaneous Adjustments

In its direct filing KCPL included several adjustments that were required to be made to certain of KCPL's 2007 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. Staff made the same adjustments to test year account balances as proposed by KCPL in its Adjustment No. 11.

Staff Expert: Charles R. Hyneman

15. Non-Operating Costs in Account 923.1.

This adjustment was required to remove certain non-operating costs from KCPL’s cost of service. These costs include amounts that were billed to KCPL by Great Plains Energy Service (GPES), such as interest expense and earnings tax. Both the Company and Staff made this adjustment. (Staff adjustment E-160.1 adjusts KCPL’s test year 2007 for this expense.)

Staff Expert: Paul R. Harrison

16. Amortization of Demand-Side Managements Costs-Regulatory Asset

The Demand-Side Management (DSM) Account 182440 contains costs that have been incurred for fourteen (14) DSM programs[16] that are in various stages of development and implementation, along with (1) costs not directly assignable to any individual program, and (2) DSM market research costs. At this time, Staff has no adjustments to the DSM Account.

Based on Staff's participation in the Customer Program Advisory Group, established to advise KCPL in the development of DSM programs, and Staff's review of the costs in Account 182440, Staff has treated the previously mentioned amounts according to the amortization process agreed to in the KCPL Regulatory Plan Stipulation and Agreement, entered into in Case No EO-2005-0329.

The Stipulation and Agreement provides for construction accounting which allows KCPL to capitalize an interest amount on the project costs in the regulatory asset account at the AFUDC rate used for capitalizing an interest (return) cost on other capital projects during construction.

The DSM costs include the payments to KCPL's customers that participate in the MPower Program. The MPower Program is a commercial and industrial load curtailment program. This program allows KCPL to call for curtailment for economic reasons. Staff is allowing these costs to be included in the DSM account because the revenues from such sales on the wholesale market will be returned to the retail customers through a mechanism established by the Commission in a previous KCPL rate case, Case No. ER-2006-0314. Staff adjustments in this case for KCPL's DSM deferrals are reflected in Staff adjustment E-139 which includes the amortization of the Vintage 1-ER-2006-0314 deferrals of $239,666, the amortization of Vintage

[16] DSM programs include demand response and energy efficiency programs, including the low income weatherization programs.

2-ER-2007-0291 deferrals of $448,624, the amortization of Vintage 3-ER-2009-0089 deferrals of $483,970 and the removal of the DSM amortization booked in the test year of $356,632.

In addition to the adjustments to reflect the amortizations of the different vintage balances, adjustment E-139 also include three adjustments to reflect KCPL's 7.29% AFUDC return for September 2008 on the unamortized DSM deferrals by vintage.

The balance of vintage 3 ER-2009-0089 per KCPL's books and records were adjusted to remove the Missouri jurisdictional portion of the Surface Transportation Board complaint case refunds, remove the amount of KCPL's 2007 off-system sales margin in excess of the amount directly included in rates in the ER-2007-0291 case adjusted for interest accrued, and reflect the transfer of certain DSM related advertising costs charged to KCPL's income statement advertising accounts.

Staff noted that in 2009 KCPL received revenues from the performance of storm restoration duties on behalf of other utilities in Missouri and in other states. To the extent these revenues were booked within the test year true-up period, Staff will ensure that KCPL's cost of service appropriately reflects the receipt of these revenues and that Missouri customers will not be charged for the payroll and benefits and other costs reimbursed to KCPL from these utilities. If it would be appropriate to include additional revenues received from these other utilities in this case, Staff would include this amount as an offset to KCPL's DSM deferral.

Staff Experts: Adam C. McKinnie and Charles R. Hyneman

17. Interest On Off-System Sales Margin

In Case No. EO-2005-0329, the Commission approved a Stipulation and Agreement among KCPL and others that contemplated an Experimental Regulatory Plan. Under the terms of the Stipulation and Agreement, KCPL agreed that off-system energy and capacity sales revenues, and related costs, will continue to be treated "above the line" for ratemaking purposes.

KCPL also agreed that it would not propose any adjustment that would remove any portion of its off-system sales from its revenue requirement determination in any rate case during the life of the Experimental Regulatory Plan.

In its first rate case after the Commission approved the Experimental Regulatory Plan for KCPL, Case No. ER-2006-0314 the Commission determined that in setting KCPL's rates, the amount included in KCPL's revenue requirement for off-system sales should be the 25th percentile of non-firm off-system sales margin, that KCPL book all amounts above the 25th percentile as a regulatory liability, but no corresponding regulatory asset would be booked should sales fail to meet the 25th percentile.

In KCPL's next general rate case, Case No. ER-2007-0291, the Commission continued this approach and ordered that KCPL pay a short-term interest rate of LIBOR plus 32 basis points on all margin amounts that exceed the 25% level, with the interest paid not charged to ratepayers in cost of service. The Commission did not specify how it expected this interest paid not be charged to ratepayers in cost of service. Staff is proposing in this case that excess rate recovery of off-system sales margins plus accrued LIBOR interest for the 2007 calendar year be be returned to KCPL's customers through a reduction to KCPL's Demand Side Management (DSM) regulatory asset deferral. Staff will include the 2008 calendar year excess margin amount in its true-up filing in this case.

Staff Expert: Charles R. Hyneman

<u>18. Vegetation Management and Infrastructure Inspection Program</u>

The Commission recently adopted new rules regarding vegetation management and infrastructure inspections. The Company proposed an adjustment to its test year level of expense for vegetation management and infrastructure inspections to reflect the requirements contained in these new rules. Since the Company filed its Direct Testimony, it has been evaluating proposals from various subcontractors regarding work required in order to comply with the new rules. The Company has recently awarded several contracts designed to carry out the vegetation management work and it is in the process of evaluating proposals regarding infrastructure inspection.

Staff proposes to treat the ongoing costs of vegetation management and infrastructure inspection in the same way as was ordered by the Commission in Case No. ER-2008-0318, AmerenUE's recent rate case. This approach would include in rate base an amount intended to reflect the expected ongoing costs for vegetation management and infrastructure inspection, but would not include the cost of repairs. In addition to the inclusion of this base amount, Staff's approach would provide for the establishment of a two-way tracker that would begin when the rates for the Company's currently filed rates go into effect and continue until the effective date of the rates resulting from the Company's next rate case. Finally, Staff's approach provides for an annual tracker limit (cap) of 10% above the included base amount.

Staff Expert: Daniel I. Beck

19. 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 associated with unanticipated losses for property assets and personal injury from accidents. Certain forms of insurance reduce ratepayer's exposure to risk. Premiums for insurance are normally pre-paid by utilities; i.e., payment is made by the utility to the insurance vendor in advance of the policy going into effect. These insurance payments are normally treated as prepayments, with the amount of the premium being booked as an asset and amortized to expense ratably over the life of the period the insurance is in force. The unamortized balance of the prepaid insurance account (either the period-ending balance or a 13-month average balance) is included in rate base, with an annualized level of insurance expense included in rates.

During the audit, Staff reviewed the Company's insurance policies for the following forms of insurance:

- Crime
- Fiduciary Liability
- Directors and Officers
- General Liability/Umbrella
- Excess Directors & Officers
- Excess Liability
- Excess Fiduciary
- Workman's Compensation
- Excess Workman's Compensation
- Property
- Labor Management Trust Fiduciary
- Excess Property
- Auto Liability
- Bonds

Staff reviewed the policies and verified the current insurance premiums for each insurance type. An annualized amount was determined and allocated to GMO to be reflected in GMO's cost of service in (Case Nos. ER-2009-0090 and HR-2009-0092). Adjustment E-161 reflects the annualized levels for KCPL portion of the insurance costs.

Staff Expert: Karen Herrington

20. Injuries and Damages

Injuries and Damages relates to insurance for claims that are not covered by the Company's insurance policies. Injuries and Damages usually consist of claims associated with

General Liability, Workman's compensation, and Auto Liability. The Commission ruled in the rate case ER-2006-0314 the accrual method of accounting should be used when calculating the costs associated with Injuries and Damages. Staff believes the accrual method is not an accurate method to use to determine the appropriate costs associated with Injuries and Damages. The accrual method is an estimate of what the Company may pay for future claims, but what will be paid on these claims is not actually known. As such, the estimates do not meet the criteria of known and measurable costs used in the ratemaking process. Staff analyzed three years of data and determined a three-year average including the period of 2006 through 2008, using the actual cash payments to normalize the Company's costs associated with Injuries and Damages. These actual cash payments are those paid to individuals who had injury and claim against the Company. As a result of these injuries, KCPL made cash settlements. A three-year average was used based on the data received from the Company in addition to the upward trend of the cash payments in the years mentioned above. Adjustment E-164 reflects a normalized level of costs for injuries and damages.

Staff Expert: Karen Herrington

21. Accounting Authority Orders

Accounting authority orders ("AAO") are Missouri Public Service Commission ("MPSC or Commission") authority to use a specific accounting treatment for a category of expense than that it would otherwise be required to use.

Utilities generally request an AAO because of a cost the utility incurs due to an extraordinary event. Without the desired accounting treatment requested from the Commission, the ability of the utility to request future rate recovery of the extraordinary expense might be impaired. Therefore, the utility will file an application for an AAO.

KCPL filed an application for an AAO in 2002 as a result of extraordinary costs it incurred associated with an ice storm in the Greater Kansas City area. The case was designated as Case No. EU-2002-1048. The Commission granted the AAO which allowed the Company to amortize the costs associated with the ice storm over a 5-year period. The amortization began in January 2002 and ended in January 2007. Upon review of the Company records, Staff determined the monthly amortization amount for January 2007 was included in the test year account balance. Effective January 31, 2007, the amortization associated with this ice storm ended and as such will no longer be a cost for the Company going forward. Therefore, Staff made an adjustment to remove the amortized amount included in the test year. Adjustment E-118.

Staff Expert: Karen Herrington

22. Surface Transportation Board Reparation Recovery

On October 12, 2005, KCPL filed a rate complaint case with the Surface Transportation Board ("STB") against Union Pacific Railroad ("UPRR") alleging UPRR's charges to transport coal from Wyoming's Powder River Basin (PRB) to KCPL's Montrose plant in Missouri were excessive.

On May 15, 2008, the STB ruled in favor of KCPL, and ordered UPRR to reduce its rates to KCPL and pay KCPL reparations for prior overcharges. The STB estimated the value of the rate reductions and reparations to be $30 million.

During the period between the STB rate complaint case and the final decision, KCPL had two rate cases before this Commission, Case No. ER-2006-0314 and Case No. ER-2007-0291. In Case No. ER-2006-0314, Staff and KCPL, by agreement, treated KCPL's actual STB litigation costs as a regulatory asset amortized to expense over five (5) years beginning in

January, 2007. Staff and KCPL also agreed that proceeds from the complaint were first to be applied as an offset to any existing balance of the STB case costs in the regulatory asset, with the remainder being applied to offset fuel costs as determined in future proceedings. The Commission, in its Report and Order in that case observed that the agreement between Staff and KCPL "appears just and reasonable."

In KCPL's next Missouri rate case, Case No. ER-2007-0291, Staff and KCPL continued this same treatment of deferring and amortizing the Missouri jurisdictional portion of KCPL's STB litigation costs. Staff also included a return on these STB case-deferrals as a separate adjustment in Staff's revenue requirement schedules.

In its September 30, 2008 update workpaper (adjustment 62), KCPL calculated an excess of rate recovery for STB costs and reparations from UPRR in excess of its STB costs of $1.38 million. KCPL distributed this excess to the three entities that it claims contributed funds to the cost of prosecuting the STB case. These entities are the City of Independence (through its capacity contract with KCPL), Missouri regulated customers and Kansas regulated customers. In addition, KCPL allocated the excess to its wholesale customers who apparently did not contribute funds to the cost of the STB complaint case.

KCPL updated this workpaper on February 4, 2009, based on corrected information and included additional reparations received from UPRR. Staff used the calculation methodology used in KCPL's updated workpaper, with two corrections.

First, KCPL failed to include all of the funds included in ER-2007-0291 rates in the total amount of the STB costs contributed by Missouri ratepayers. Staff added $143,945, the amount KCPL collected in rates from January 2008 through September 2008. This amount was earmarked for STB case expense recovery, but was excluded by KCPL in its calculation.

Also, since it does not appear that KCPL's wholesale customers contributed to the STB rate case recovery, Staff reallocated their credited amount to Missouri and Kansas regulated customers by using the appropriate Missouri-Kansas allocation percentage.

Similar to how the Staff is treating the excess amount of Off System Sales over the amount in rates, the Staff is also proposing to treat the STB reparation costs as a reduction to rate base. While it is more theoretically correct to reduce fuel related rate base components, for convenience and for accuracy in the tracking of these reparation recoveries, the Staff is reducing KCPL's Demand Side Management (DSM) regulatory asset deferral by Missouri's appropriate share of the STB reparation costs as of September 30, 2009.

Staff Expert: Charles R. Hyneman

23. Officer Expense Account Adjustment

This adjustment reflects Staff's current estimate of potential costs charged to KCPL's 2007 books and records as a result of excessive and or inappropriate charges made by KCPL and GPE officers through their employee expense reports. Staff is concerned not only with the potential for excessive and inappropriate charges being included in KCPL's cost of service in this case, but with also the continued lack of internal controls on the officer expense report process and the general lack of concern on the part of Company management about costs charged to regulated operations through officer expense reports.

In a press release issued on September 5, 2008 announcing the filing of the Missouri rate case, Michael Chesser, GPE's CEO stated that:

> We do not relish requesting a rate increase during these difficult economic times," said Chesser. "However, these requests are approximately $23 million less than they would have been, as a direct result of operational savings realized from our acquisition of Aquila. We will continue to focus on keeping our costs as low as possible and providing ways for customers to have greater control over their electricity use and bills.

Based on its review of the Company's expense report process, Staff cannot agree that KCPL is continuing to focus on keeping costs as low as possible. Staff cannot see any concern about excessive or inappropriate charges in this area. Staff believes that the concern about costs in the expense report process has to be a priority of top management.

Tone at the top is a general term that refers to leadership behavior setting an example to the rest of the company employees. In the area of cost control, "tone at the top" is very important. Whatever tone management sets will have a trickle-down effect on employees of the company. If the tone set by officers of the company reflects strict adherence to established expense report policies and procedures, lower ranking employees will be more inclined to strictly adhere to those same policies. Employees pay close attention to the behavior and actions of their bosses, and they follow their lead. They only way for GPE and KCPL to correct the continued problems KCPL has with its expense report process is for the leadership of the Company to change the current tone at the top and focus on cost control and adherence to the Companies own policies and procedures.

On January 17, 2007 GPE's Audit Services Department (Audit Services) released a report entitled *Great Plains Energy Services Kansas City Power & Light Officers and Directors Expense Report Review*. In that report, Audit Services found that it was "difficult to determine the business purpose" of expenses included in some of expense reports reviewed. Audit Services concluded that "based on our testing, it appears that the controls in place are not working properly."

In April 2008 Audit Services released another report entitled *Great Plains Energy Officers and Directors Expense Report Review.* This report includes a *Summary Schedule of Prior Year Findings* and *Current Status of Prior Year Findings.* Audit Services noted that while it appeared corrective actions was being taken, there were still large incidences of non-compliance. Audit Services found that the documentation of business expenses is generally not in compliance with nor as robust as the documentation requirements prescribed by GPE's own expense report polices and the requirements of the Internal Revenue Service. Audit Services concluded that the "lack of clear and concise documentation created some difficulty in identifying the business purpose of the expense."

Staff's review of KCPL employee expense reports confirms the findings of GPE's Audit Services Department, and finds additional discrepancies. For example, one KCPL officer is a board member of the National Association of Manufacturers (NAM). For the past several years this individual has been charging his trip expenses for NAM board meetings to KCPL customers. In one expense report, Staff noted lodging expenses of $774 for the Ritz Carlton Hotel in Orlando, Florida and airfare of $632 to Orlando for attendance at the NAM board meeting. These expenses were charged to project CORPDP-KCPL which is described in KCPL's accounting records as:

> This project is used to capture costs to provide resource planning and business analysis services, strategic planning, assist in the development of fundamental short- and long-term business plans and actions which are consistent or complementary throughout the system; assess and adjust the decisions and direction of system companies in response to changes in the marketplace; provide consulting services related to cost reduction opportunities, strategic acquisitions and investments, and process enhancements to KCPL, but not specifically related to any operating unit or service location. Thus, all costs collected in this project will be billed to the various KCPL Business Units based on the basis of KCPL Headcount.

This same expense report also includes airfare to New York for a GPE Board of Director retreat. All of the expenses in the report were incurred in February and March 2007, but the expense report was not approved until three months later in June 2007.

An additional concern of Audit Services was that the expense reports of the Chairman and Chief Executive Officer (CEO) of GPE are approved by the President and Chief Operating Officer (COO) of GPE. This is a case of a subordinate approving the expense reports of his/her superior and is a bad internal control policy. In addition to being a bad internal control policy, the process violates GPE's own expense account policies that require that expense reports must be approved by an employee of equivalent or higher rank. To correct this issue, Staff recommends that the expense reports of both the CEO and COO of GPE be approved by the Audit Committee of GPE's Board of Directors.

Finally, Staff has a major concern with the charges for meals and lodging to KCPL by the officers of KCPL. During its audit, Staff noted on a particular officer's expense reports a meal charge for two individuals in the amount of $400 and on another expense report a meal for two individuals in the amount of $300. Staff views these amounts to be clearly excessive. In addition, Staff noted that another executive included a $144 charge for wine on a KCPL expense report. Staff also views that charge inappropriate.

Because of the longstanding problems with KCPL's and GPE's officer expense reports and the serious concerns Staff has developed as a result of the small sample of officer expense reports Staff reviewed in this case, Staff has decided to make an adjustment in this filing of the estimated amount of improper expense account charges booked to KCPL's 2007 books and records and to expand its review of the KCPL and GPE officer expense reports. Staff expects to update this adjustment in its true-up revenue requirement filing in this case.

24. Wolf Creek Nuclear Refueling Outage

KCPL defers and amortizes over 18 months (the time period between refueling outages) the actual cost incurred during the refueling outage. Over the last three refuelings (2003, 2005 and 2006) the average outage period was 33 days, with the outage in 2006 lasting 34 days. The 2008 refueling lasted 56 days or an increase of 70 percent above the average refueling outage days. Because of this abnormal event, the cost of the outage increased significantly. The reasons for this outage are described in KCPL's 3rd quarter 2008 10-Q filing with the Securities and Exchange Commission:

> Wolf Creek's latest refueling outage began on March 20, 2008, and there were several increases in work scope during the outage that extended the restart until May 14, 2008. A primary driver of the work scope increases was modifications to piping systems associated with the emergency core cooling systems.

Because rates are set on annualized and normalized expense levels, Staff determined that the cost reflected in KCPL's test year, based on the 2006 refueling outage of 34 days is an appropriate normalized level of refueling expense. Since this is the amount reflected in KCPL's test year, no adjustment was made.

Staff Expert: Charles R. Hyneman

25. Rate Case Expense

Rate case expenses are costs incurred by a company in preparation and performance of its filing for rate increases. In this case, KCPL has incurred expenses in conjunction with legal counsel, regulatory consulting and outside consultants.

Staff usually treats rate case expense as a normalized recurring expense necessary to provide utility service. This treatment involves determining the cost to process a rate case on a normalized level and reflecting that cost in the cost of service. However, because of KCPL's regulatory plan and the resulting recurring rate cases, Staff has agreed with KCPL to use a different approach. Since Case No. ER-2006-0314, Staff has agreed to use a "defer and amortize" approach for KCPL rate case expense instead of its traditional normalized cost approach.

KCPL's "defer and amortize" approach is to defer the rate case expenses for each rate case as a separate vintage deferral and amortize each of those vintage deferrals over a two-year period. The rate case expense KCPL incurred after end of the true-up period in one case will be transferred to the next rate case to be recovered in the rates established in that case. This special treatment for rate case expense is expected to end in KCPL's final rate case under its Regulatory Plan, which is designated as the Iatan 2 rate case and which is expected to be filed later this year.

Staff reviewed Company records and responses to data requests to determine the correct amount of rate case expense for inclusion in KCPL's cost of service in this case. Staff requested actual billings and invoices from KCPL to examine the reasonableness of these costs. Staff included in this case the actual amounts determined to be reasonable based on invoices that were provided. Staff Adjustment E-172 reflects an amount for rate case expense to be recovered over a two-year period for the costs incurred by KCPL to process this rate case before the Commission. Staff adjustment E-172 reflects an adjustment to include the 2nd year of rate case expense KCPL incurred in Case No. ER-2007-0291.

While Staff agreed to use the KCPL defer and amortize approach for the rate cases included in its Regulatory Plan, Staff does not believe this approach is an appropriate ratemaking method for rate case expense. The "defer and amortize" approach distorts the normal process of regulatory lag by allowing for a potential over recovery of the expense (if the period between rate cases is more anticipated) but by virtue of the use of the vintage approach of segregating the costs into specific sections for each rate case, the "defer and amortize" approach eliminates any potential for under recovery. This distortion of the normal flow of regulatory lag unfairly favors the Company's shareholders to the detriment of its customers.

For example, in their first case under Regulatory Plan No. ER-2006-0314, KCPL's rate case expense was $1,066,118. KCPL's actual rate case expense costs were $1,397,723, but $331,605 of that cost was incurred after the true-up date in that case and was transferred to the rate case expense deferral for KCPL's second Regulatory Plan rate case, Case No. ER-2007-0291. The two-year period for the ER-2006-0314 deferral began in January 2007 and ended in December 2008. KCPL filed the current 2009 rate case on September 5, 2008; and therefore, rates are unlikely to become effective before August 2009. As a result, the amount that KCPL will recover in existing rates for the rate case costs from the 2006 rate case (Case No. ER-2006-0314) will continue to be recovered over seven months after the end of 2008. When viewed in isolation, KCPL will over-recover the 2006 rate case costs. This over-recovery will be tracked by Staff and will be offset against future rate case expense.

As of the true-up date in this rate case, March 31, 2009, KCPL will have over-recovered $133,265 of the vintage 2006 rate case expense. This amount will be credited against KCPL's current rate case expense in Staff's true-up rate case expense adjustment. Any amount recovered for the 2006 rate case will continue to be tracked subsequent to March 31, 2009 up to the time rates change in this case, and will be used to offset any 2007 or 2009 rate case expense amounts. Staff believes that rate case expenses are unique costs to process rate cases in the regulatory environment resulting in material costs being incurred at the end of the case beyond the update and true-up periods. Using this tracking mechanism allows KCPL to recover its rate case costs, but it should not be used to permit KCPL to over-recover its rate case expenses without the corresponding risk that the costs will be under recovered. (Income Statement Adjustment E-172)

Staff Expert: Bret G. Prenger

26. Public Service Assessment Fee

The Public Service Commission assessment (PSC Assessment) is an amount billed to all regulated utilities operating under the jurisdiction of the Commission as an allocation of the Commission's operating costs for regulating those utilities. The PSC Assessment is charged to regulated utilities operating in Missouri.

KCPL's PSC Assessment was annualized using the latest assessment available for the current fiscal year (FY-2009) on information obtained from the Commission's records. The updated KCPL PSC Assessment was compared to the PSC Assessment amount included in KCPL's test year to form the basis for the adjustment in Staff's cost of service run. The PSC Assessment adjustment is Staff Accounting Adjustment E-171.

Staff Expert: Bret G. Prenger

VIII. Depreciation

Staff recommends that KCPL's current authorized depreciation rates from Case No. ER-2007-0291 be used to develop the revenue requirement in this case. These rates are presented in Schedule 3-1, 3-2, and 3-3 and reflect the same rates presented in Schedules G-1, G-2, and G-3 to the Stipulation and Agreement in KCPL's Case No. EO-2005-0329 regarding the Company's regulatory plan.

In response to Staff recommending to the Commission that it lower KCPL's depreciation rates in Case No. ER-2006-0314, a case where KCPL was receiving rate recovery of regulatory plan amortizations, the Commission stated in its Report and Order, "(w)hat is more, any decrease in depreciation likely would not affect rates in this case because KCPL would be allowed additional amortization to meet the credit metrics agreed to in Case No. EO-2005-0329." The same situation exists in this proceeding where any changes to KCPL's depreciation rates would not affect the customer rates the Commission establishes in this case.

Staff Expert: Rosella Schad

IX. Current and Deferred Income Tax

A. Current Income Tax

Current income tax for this case has been calculated by Staff consistent with the methodology used in KCPL's last rate case, Case No. ER-2007-0291. A tax timing difference occurs when the timing used in reflecting a cost (or revenue) for financial reporting purposes is different from 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 tax regulations. 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. A tax credit was reflected in KCPL's last case for research and development costs. The tax timing differences used in calculating taxable income for computing current income tax for KCPL are as follows:

Add Back to Operating Income Before Taxes:

- Book Depreciation Expense
- 50% Meals and Entertainment Disallowance
- Book Nuclear Fuel Amortization
- Book Amortization Expense

Subtractions from Operating Income:

- Interest Expense – Weighted Cost of Debt X Rate Base
- IRS Accelerated Tax Depreciation
- Deduction for Electric Utility Production Income
- IRS Nuclear Fuel Amortization
- IRS Other Amortization Deduction

Subtractions Federal Income Tax Credit:

- Wind Production Tax Credit
- Research and Development Tax Credit:

The tax credit for research and development expenditures was reflected for setting rates by Staff in the calculation of current income tax in KCPL's last case, Case No. ER-2007-0291. In that case, in response to U.S. Department of Energy (DOE) Data Request No. 55, KCPL indicated that it intended to file amended tax returns for years 2001-2005 for the purpose of reflecting allowable tax credits and current year tax deductions for research and experimental expenditures under Internal Revenue Code (IRC) Sections 41 and 174. It is Staff's position that the additional cash flow from a tax reduction from an amended tax return should be deferred and amortized for ratemaking purposes. This increase in cash flow to KCPL should be used to mitigate the Regulatory Plan Additional Amortization that KCPL's ratepayers are paying in current rates and will continue to pay until rates become effective in 2010 to recognize the "fully operational and used for service" date for KCPL's new coal burning generating facility, Iatan 2.

The occurrence of an extraordinary income event should be viewed in the same manner as an extraordinary cost event like KCPL's 2002 ice storm. Deferred accounting and amortization for ratemaking purposes should apply equally to both extraordinary costs and extraordinary income. KCPL's failure to take advantage of all available tax credits in prior years should not result in a cash windfall for its shareholders, but instead should be used to reduce the additional cash requirement collected from ratepayers in the Regulatory Plan Additional Amortization. The amount of additional cash flow provided by ratepayers through the Regulatory Plan Additional Amortization should be limited to funds unavailable from other sources.

Wind Credits used to reduce current income taxes relate to credits the Company is allowed from its ownership of the Spearville Wind Farm located in western Kansas and "fully operational and used for service" in September 2006. The Wind Credits were also taken as a reduction to current income taxes by Staff and reflected in rates as a result of KCPL's last rate case.

Additionally, Staff and Company made an adjustment to remove the Kansas City, Missouri earning tax from the Company's general ledger and included it in the Staff's Schedule 11, Income Tax. This adjustment does not affect Staff's revenue requirement and by including it in the current income tax calculation, all of the current income taxes are tracked on the same schedule.

B. 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 as the result of the 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 Stipulation and Agreement in Case No. ER 2006-0314 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. Staff's deferred income tax calculation treats the Regulatory Plan Additional Amortization, approved in Case No. ER 2006-0314, as an increase in the straight-line tax depreciation deduction, consistent with the Stipulation and Agreement approved in Case No. ER 2006-0314.

Any increase in the Regulatory Plan Additional Amortization resulting from the results of Staff's true-up audit will also be reflected in the deferred income tax calculation for this case, ER-2009-0089.

Staff Expert: Paul R. Harrison

C. Current and Deferred Income Tax

KCPL's deferred income tax reserve represents, in effect, a prepayment of income taxes by KCPL's customers. As an example, because KCPL is allowed to deduct depreciation expense on an accelerated basis for income tax purposes, depreciation expense used for income taxes is significantly higher than depreciation expense used for financial reporting (book purposes) and for ratemaking purposes. This results in what is referred to as book-tax timing difference, and creates a deferral, or future liability of income taxes, to the future. The net credit balance in the deferred tax reserve represents a source of cost-free funds to KCPL. Therefore, KCPL'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 which are created through the ratemaking process should be reflected in rate base. Besides accelerated depreciation, Staff has also included deferred taxes specifically associated with the rate base inclusion of the pension liability.

Prior to the 1986 Tax Reform Act, flow-through treatment (current year deduction) was used for Missouri utilities unless the utility could demonstrate the need for additional cash flow to meet interest coverage ratios. It is Staff's understanding that KCPL received normalization treatment in rate cases prior to 1986 based upon a need for additional cash flow during significant construction activity related to new generation facilities.

Timing differences which were reflected as a tax deduction in the current year, for current income tax to the IRS, were deferred (normalized) for ratemaking purposes. The tax deduction is reflected in rates by amortizing the deferred tax balance over the depreciable life of the property. Staff's income tax calculation for KCPL, in this current case, reflects the amortization of prior timing differences which were normalized in prior rate cases. Adjustment E-212.1 reflects an annual amortization of deferred taxes resulting from normalization treatment in prior cases.

The 1986 Tax Reform Act reduced the federal tax rate for corporations from 46% to 34%. As a result all deferred taxes, previously reflected in rates, based upon an assumed 46% tax rate, were overstated. The IRS allowed a regulated utility to flow back (amortize) to ratepayers the excess deferred taxes over the approximate depreciable book life of the property. Staff's income tax calculation for KCPL in this case reflects an amortization of excess deferred taxes resulting from the reduction in the federal tax rate in 1986. Adjustment E-211.1 reflects an annual amortization of the excess deferred taxes resulting from the reduction in the federal tax rate.

Prior to the 1986 Tax Reform Act, a utility received a permanent tax credit for investing in new capital additions. For ratemaking purposes, the IRS allowed the utility to amortize (flow back to ratepayers) the investment tax credit over the approximate depreciable book life of the related property. Adjustment E-209.1 reflects an annual amortization of the deferred investment tax credit which was in effect prior to the 1986 Tax Reform Act.

Beginning in 1971, the IRC imposed restrictions that prevented the use of Investment Tax Credit (ITC) as a reduction to Rate Base. Since the restrictions do not apply to Pre-1971 ITC, it is being provided the same treatment by Staff as other deferred income taxes that have been funded by the ratepayer. (Rate Base Schedule 2.)

Staff Expert: Paul R. Harrison

X. Jurisdictional Allocations

Jurisdictional allocation refers to the process by which demand-related and energy-related costs are allocated to the applicable jurisdictions. Fixed costs, such as the capital costs associated with generation and transmission plant, are allocated on the basis of demand. Variable costs, such as fuel, are more appropriate to allocate on the basis of energy consumption. In this Case, jurisdictional allocation factors for demand and energy are calculated to assist in allocating demand related (fixed) costs and energy-related (variable) costs between four applicable jurisdictions: Missouri and Kansas retail and Missouri and Kansas wholesale operations. The application of a particular jurisdictional allocation factor is dependent upon the types of costs being allocated.

A. Methodology

1. Demand Allocation Factor

Demand refers to the rate at which electric energy is delivered to a system to match the energy requirements of its customers, generally expressed in kilowatts or megawatts, either at an instant in time or averaged over a designated interval of time. System peak demand is the largest electric requirement occurring within a specified period of time (e.g., hour, day, month, season, and year) on a utility's system. In addition, for planning purposes, an amount must be included for meeting required contingency reserves. Since generation units and transmission lines are planned, designed, and constructed to meet a utility's anticipated system peak demands plus required reserves, the contribution of each of the four individual jurisdictions coincident to these system peak demands is the appropriate basis on which to allocate the costs of these facilities. Thus, the term coincident peak (CP) refers to the load, generally in kiloWatts (kWhs) or megaWatts (MWs), in each of the jurisdictions that coincide with KCPL's overall system peak recorded for the time period used in the corresponding analyses.

Staff utilized a 4CP method in its determination of demand and energy allocation factors, the same method utilized in the two most recent Rate Cases involving KCPL (ER-2006-0314 and ER-2007-0291). The demand allocation factor for each jurisdiction was determined using the following process:

1. Identify KCPL's peak hourly load in each month of the four -month period June 2007 through September 2007 and sum the hourly peak loads.

2. Sum the particular jurisdiction's corresponding loads for the hours identified in a. above.

3. Divide b. above by a. above.

The result is the allocation factor for each jurisdiction:

- Missouri Retail Operations: 0.5387
- Missouri Wholesale Operations: 0.0021
- Kansas Retail Operations: 0.4544
- Kansas Wholesale Operations: 0.0048

These jurisdictional demand allocation factors were provided to Staff Witness Cary Featherstone.

2. Energy Allocation Factor

Variable expenses, such as fuel, are allocated to the jurisdictions based on energy consumption. The energy allocation factor for an individual jurisdiction is the ratio of sum of the monthly kilowatt-hour (kWh) usage in the particular jurisdiction for the months of June 2007 through September 2007 to KCPL's total system kWh usage. Staff has calculated the following energy allocation factors for the particular jurisdictions:

- Missouri Retail Operations: 0.5664
- Missouri Wholesale Operations: 0.0022
- Kansas Retail Operations: 0.4262
- Kansas Wholesale Operations: 0.0052

These jurisdictional energy allocation factors were also provided to Staff Witness Cary Featherstone.

Staff Expert: Alan J. Bax

B. Application

KCPL operates within two state jurisdictions, Missouri and Kansas, and in the federal jurisdiction regulated by FERC. Therefore, it is necessary to specifically identify, allocate and/or assign utilities' investment and expenses between these various jurisdictions. In order to develop a fully comprehensive cost of service analysis to identify the revenue requirements, all costs incurred by the Company for plant investment and income statement costs must be specifically placed in all of the jurisdictions served. The allocation process identifies these costs between the state and FERC jurisdictions.

Staff applied the demand factor developed based on the 4 CP methodology to the production and transmission plant and related depreciation reserve accounts. These asset accounts relate to the fixed assets of KCPL for the generating facilities used to generate electricity and the transmission facilities used to transport electricity to KCPL retail customers in Missouri and Kansas as well as the FERC wholesale customers in both states. This same infrastructure is used to generate and transport electricity to firm and non-firm customers in the bulk power markets (off-system sales).

The Company specifically identifies the distribution plant by state jurisdiction. This is referred to as site specific or situs plant and Staff used allocation factors for distribution plant and reserve to identify only the distribution plant specific to Missouri operations.

The FERC expense accounts found in the income statement (Schedule 9 of the EMS model) are broadly categorized as production, transmission, distribution and general. The allocation factors used to identify costs to a specific jurisdiction are based on the allocation factors used to allocate plant costs. The demand allocation factor used to allocate the production plant accounts to their respective jurisdictions is also used to allocate income statement costs for production and transmission. Using the plant allocators to allocate costs to the specific jurisdiction is referred to as "expenses follow plant." The demand plant allocation factor used to allocate production and transmission plant costs is the same demand allocator used to allocate production and transmission expenses in the income statement. Production plant allocators are appropriate to use in the income statement for the production expenses. These expenses are associated with maintaining and operating the production plant. The demand factor is also used to allocate the transmission plant and depreciation reserve and in turn, is used to allocate transmission expenses found in the income statement for the costs to maintain and operate the transmission network.

The common facilities or general plant are allocated based on a composite of the demand allocation factor used to identify production, transmission and distribution costs. Once the plant and depreciation reserve are allocated based on demand allocators for production and transmission plant and site specific allocation factors for distribution plant costs, the state jurisdictions allocation factors for general plant are based on the composite for the production, transmission and distribution plant costs. The composite general plant allocation is used to allocate general costs in the income statement.

For administrative and general costs, commonly referred to as the A&G costs, a variety of allocation factors were used to allocate these costs to the various expense accounts found in the income statement. Staff relied on the Company to identify and determine these allocation factors. The various allocation factors used were based on customers found in each jurisdiction in some cases. Other times, the factors used were based on employees in each jurisdiction. Each specific account had its own allocation factor that was used to allocate costs to Missouri, Kansas and/or FERC operations.

The energy allocation factor was used to allocate costs that are considered variable in nature. Variable costs fluctuate directly with increased or decreased electricity output. For example, the costs related to the variable component of fuel and purchased power expenses vary with increased or decreased loads. As more or less megawatts are generated or purchased, increased or decreased fuel and purchased power costs are directly affected. The fixed capacity, or demand charge, of purchased power is allocated using the demand allocator, the same one used to allocate the fixed production and transmission costs. Fixed costs do not vary with electricity output.

Staff Expert: Cary Featherstone

XI. Transition Cost Recovery Mechanism

On April 4, 2007, GPE, KCPL and Aquila (Joint Applicants) filed an application with the Commission seeking authority for a series of transactions whereby Aquila would become a direct, wholly-owned subsidiary of GPE. On July 1, 2008, the Commission approved the acquisition.

In the Report and Order approving the acquisition (the Acquisition Order), the Commission concluded that it is not a detriment to the public interest to allow recovery of transition costs of the acquisition. In paragraph 6c. of the Ordered Section of the Acquisition Order, the Commission directed the Joint Applicants to implement a synergy savings tracking mechanism utilizing a base year of 2006.

In the Acquisition Order, the Commission agreed that there was the potential for significant savings as a result of the acquisition and was supportive of the recovering of costs incurred in combining the operations of KCPL and Aquila (transition costs). While it did support recovery of the transition costs, the Commission did not specify the method with which this recovery is to be accomplished. Transition costs are those costs incurred primarily post closing of the merger to integrate the operations of the two companies.

In Ordered paragraphs 13 of the Acquisition Order, the Commission stated that "nothing in this order shall be considered a finding by the Commission of the value for ratemaking purposes of the transactions herein involved." And in paragraph 14 it said that the Commission "reserves the right to consider any ratemaking treatment to be afforded the transactions herein involved in a later proceeding."

In this section of Staff's Cost of Service Report, Staff will describe its recommendation to the Commission regarding what it believes is the best approach to handle the issue of recovery of the transition costs related to this acquisition.

There are two methods by which a utility can recover acquisition or merger transition costs. They are direct rate recovery and indirect rate recovery. Using the direct rate recovery method a utility would defer the costs, file for a rate increase and amortize the deferred costs as an increase to cost of service; the costs are recognized in the cost of service and explicitly embedded in the utility rates over a period of time through some type of amortization.

The indirect rate recovery approach to recover merger or acquisition transition costs is to defer the costs, amortize the costs to expense, but not seek direct rate recovery. Through this approach, the costs in question are recovered through regulatory lag whereby the utility's increased revenues and/or decreased expenses are sufficient to cover the increased costs of the specific event, and the utility still has the opportunity to earn its authorized rate of return.

Regulatory lag works similarly in the case of a merger or acquisition. As expenses that were embedded in rates set in the most recent rate case are no longer incurred by the acquired entity (for examples, salaries and benefits of the former Aquila officers and directors) excess rate recoveries over actual costs incurred accrue 100 percent to the utility's shareholders and can be used to reduce or eliminate the cost of the merger or acquisition first with the remaining excess rate recoveries flowing to shareholders as increases to net income.

In summary, regulatory lag is the mechanism that allows for the savings to naturally accrue to a utility, as the revenues in existing rates that were set to recover higher pre-acquisition costs (such as payroll, benefits, rents, board of director costs, property taxes etc.) no longer exist, and the savings that naturally accrue through regulatory lag over a period of time are often more than adequate to cover the costs incurred to combine the operations of the two entities.

Regulatory lag allows for a fair sharing of the benefits of a utility merger or acquisition. As a utility files rate cases during the time frame that acquisition savings are being realized, the acquisition savings are flowed through to customers as the reduced expenses of the new entity are reflected in current rates. In between rate proceedings, the new entity is allowed to retain in total the net amount of any acquisition savings it can create. Regulatory lag allows, therefore, for a fair sharing of acquisition savings between customers and shareholders, and provides the appropriate incentives for the new entity to strive for more efficient and economic operations so it can create and provide to its shareholders increased profits and benefit customers as more efficient and economic operations lower costs which are reflected in rates.

The benefits of regulatory lag as a savings incentive mechanism and a description of how GPE/KCPL/GMO plans to use regulatory lag to recover acquisition savings is explained by Terry Bassham, Executive Vice President, Finance & Strategic Development and CFO, Great Plains Energy in a GXP/ILA (GPE/Aquila) Transaction Webcast on February 26, 2008.

> Under our revised proposal, the company will retain synergies through regulatory lag rather than seeking to establish a fixed up-front sharing to be recovered over time. Synergies would now simply be retained by the company until a rate case filing, and then flow through to customers as part of the traditional regulatory process. <u>This will provide a very simple approach to synergy sharing and incent the company to move quickly to achieve synergies</u>. (emphasis added)
>
> By using the normal <u>regulatory</u> process to recover synergies we will be utilizing the concept of "regulatory lag," which represents the time between when costs are measured and documented during a "test year" and when they are put into rates. As an example, for KCP&L's most recent rate case, our 2006 test year costs, updated in the third quarter of 2007 for certain "known and measurable" components, were used to determine what costs were to be

> included in rates that went into effect in January 2008. We will utilize this type of lag to allow shareholders to reap approximately 50% of the synergy savings in the Aquila transaction through the first five years.
>
> As the chart reflects, between rate cases, the Company retains, and shareholders keep the resulting benefit of, the synergies we achieve that are not reflected in rates. Then when we file a rate case, those savings will be reflected in our cost of service and provide lower rate increases for customers. Even once the initial savings are reflected, however, we will continue to generate additional synergies which would not flow back to customers until the next rate case.

In this rate case, Staff is proposing that KCPL recover its transition costs through the regulatory lag approach to synergy savings described by Mr. Bassham. This approach recognizes that KCPL has already enjoyed the benefits of synergy savings through regulatory lag and these savings already realized can first be used to pay down the balance of unrecovered transition costs. Future synergy savings that accrue to KCPL after rates are set in this case can also be used to pay down the balance of the transition cost deferral and accrue to KCPL's shareholders.

As an example of how KCPL is currently benefiting from regulatory lag, KCPL's present rates (rates that are being paid today and will be paid until rates are changed in this case, at this time estimated to be around August 5, 2009) include all of the payroll and benefits costs of all of the former Aquila Networks - MPS and Aquila Networks - L&P employees who were terminated as of the acquisition closing date, July 14, 2008. This is a significant cost savings that can be applied to KCPL deferred acquisition transition costs. Because of this regulatory lag, the costs of severance packages in the amount of one-year salary will have been more than fully recovered when KCPL's new rates go into effect in August 2009. This example does not even include all of the other costs that are currently being recovered in rates that no longer are being incurred, such as benefits costs, which average over 50 percent of payroll costs, rents and leases, which have been terminated, board of director fees, and insurance premiums. KCPL will have recovered a significant portion of its deferred transition costs even before rates from the current rate case go into effect. The fact that KCPL has already accrued acquisition savings which can be applied to the cost of the acquisition is confirmed by William Downey, President and COO, Great Plains Energy and KCPL in a EEI Conference Webcast on November 11, 2008:

> …As Mike talked about, the integration process that John is leading, we made tremendous progress there on achieving the synergy benefits that we have promised in this. These are very contiguous territories, and we planned very hard and long ahead of the merger. I will tell you that it has gone extremely smoothly both operationally, and in terms of the communities, and in terms of achieving some of the financial benefits. <u>In fact, in our September rate case filing in Missouri, we showed a net $23 million of operating synergies already achieved that will begin accruing to our customers when rates from this rate case go into affect in the third quarter of next year.</u> We will finalize actually that amount in a first-quarter 2009 true-up in our Missouri case. (emphasis added)

In addition to the regulatory lag benefits, KCPL has been and will continue to benefit until rates are changed in this case, KCPL will also continue to recover in rates set in this case costs embedded in KCPL's test year books and records that are not being adjusted and removed from cost of service in this case. It is with absolute certainty that these costs that Staff is not proposing to remove from this case, which are no longer being incurred by KCPL but will be included in utility rates until rates are changed in a future rate case, will continue to be recovered. The next KCPL and GMO rate cases are currently estimated by KCPL to conclude around August 2010 (KCP&L is currently planning to file its next rate case in September 2009). Staff is taking the approach that, while it is annualizing payroll and other costs in this case, it has not accomplished a thorough review of KCPL's and GMO's books and records to ensure that all costs that are no longer being incurred or will no longer be incurred because of the acquisition are removed from KCPL's and GMO's revenue requirement in this case.

Staff is adopting the regulatory lag approach to transition cost recovery in this case because it is the preferred approach to the direct rate recovery method. It not only benefits customers by recognizing the regulatory lag benefits that have already accrued to KCPL and reflecting the potential cost savings in this case, but it provides KCPL with an almost limitless opportunity to retain merger savings over the next ten years.

Regulatory lag provides an incentive for utilities outside of a rate case to become more efficient and adopt the best practices of the combining entities to become a lower cost combined entity. The lower costs realized between rate cases will result in acquisition synergies that will be retained 100 percent by KCPL's shareholders.

The approach used by KCPL in this case is the direct rate recovery method. Through its Adjustment 78, KCPL is recognizing potential cost savings of a combined entity through adjustments such as payroll annualizations. It is also proposing adjustments to reduce per book amounts in accounts that are not included in its combined-company annualizations. As an offset to these adjustments, KCPL is proposing, a five-year amortization of its $34 million deferred transition balance allocated to KCPL, MPS and L&P operations.

As noted above, in paragraph 6c. of the Ordered Section of the Acquisition Order, the Commission directed the Joint Applicants to implement a synergy savings tracking mechanism utilizing a base year of 2006. Specifically, the Commission ordered that:

> Great Plains Energy, Incorporated, Kansas City Power & Light Company, and Aquila, Inc., shall, upon closure of the authorized transactions, implement a synergy savings tracking mechanism as described by the Applicants, and in the body of this order, utilizing a base year of 2006;

However, during meetings with KCPL personnel on the acquisition issue, Staff was advised that the 2006 baseline tracking mechanism ordered by the Commission was not the basis for KCPL's acquisition savings calculation in adjustment 78. Upon prodding by Staff, KCPL provided a incomplete draft version of a 2006 baseline "tracking mechanism." However, the combined 2006 baseline non-fuel Operations and Maintenance expense of $491,496,760 was adjusted by $46,125,970 or 9.4 percent before KCPL added a 3.1 percent inflation adjustment that results in a 2006 baseline, as adjusted and as inflated, of $584,763,556, or a 19 percent increase. In other words, the baseline year of 2006 was increased by almost $93 million by KCPL before any savings calculations are made.

As of the date of this filing of the Staff report, KCPL has not made any savings calculations in the 2006 base year tracking mechanism, and based on discussions with KCPL personnel, Staff is not expecting to receive an synergy savings calculation using the 2006 base year tracking mechanism for another 30 days. KCPL has advised Staff that it is waiting until proposed budgets are approved by its board of directors before it starts making savings estimates using the 2006 baseline, as adjusted and inflated by KCPL.

By choosing to use the direct method of transition cost recovery in this case, KCPL is forced to use a savings tracking mechanism to show that savings actually realized exceed the additional costs of combining the utilities. By additional costs, Staff is not referring to only the acquisition transition costs, but other potential cost increases that would not have been incurred by KCPL or GMO absent the acquisition and consolidation.

Such costs could increase salaries and union pay scales at KCPL beyond those that existed at Aquila, more expensive benefit programs, higher costs allocations of executive salaries to Missouri jurisdictional operations, a difference in focus developing cost-cutting efficiencies at the combined entities from the focus that existed at the pre-combined entities. There is a vast list of potential cost increases that may be incurred directly because of the acquisition that should be tracked under any transition cost rate recovery method proposed by KCPL and offset against the synergy savings calculation. While this would be a challenge for any company, it is especially a challenge for a company such as GPE/KCPL that reasonably argues that merger savings cannot be tracked with any degree of accuracy.

In her direct testimony in Case No. EM-2007-0374 (Exhibit 29), GPE's and KCPL's controller, Lori Wright explained that GPE did not recommend that acquisition savings be tracked. She said that in the best case there is a problem tracking savings with any degree of accuracy. The logical conclusion drawn from this statement is that in less than the best case scenario, it is not possible to accurately track acquisition savings. Ms. Wright testified as follows in Exhibit 29:

> Great Plains Energy does not recommend that synergy savings be tracked. Instead, Great Plains Energy recommends using the synergy savings identified in the Joint Application and the pre-filed testimony in support thereof. Tracking synergy savings with any degree of accuracy is problematic at best as business operations are not conducted in a static environment, but rather under constant change, including customer growth, technological improvements, etc. Tracking will become more difficult each successive year after the Merger.

To summarize, Staff is recommending to the Commission that it allow KCPL to recover its merger transition costs (a significant amount of which are currently being recovered through regulatory lag). This method is superior to the alternative direct rate recovery method which requires the use of a savings tracking mechanism which both Staff and the Company agree cannot be developed to produce accurate results.

Staff Expert: Charles R. Hyneman

XII. Service Quality

A. Post-Consolidation Service Quality of KCPL

Regulated utilities perform many processes and practices, including billing, credit and collections, meter reading, payment remittance, call center operations, service or work order processes and service disconnections and reconnections that affect the service quality experienced by their customers. As expressed in the "Staff Report of Staff's Evaluation and Recommendations Regarding Great Plains Energy Incorporated's Proposed Acquisition of Aquila, Inc.", (Staff Acquisition Report), now known as KCPL Greater Missouri Operations Company (GMO), transition challenges and events that can occur during the post-acquisition period of two regulated utilities can result in service deterioration.

Sales and merger activity create additional opportunities for service declines through the potential reduction of resources, staffing reductions, operational transitions and changes in existing utility practices, procedures and resource commitments. Transition challenges related to service quality may include such matters as the consolidation of different processes, practices, systems, procedures, cultures, organizational structures and workforces. Combining separate work forces that include union and non-union personnel, addressing customer questions, physical relocations, consolidating, revising or eliminating various processes and procedures, reassigning personnel to different positions and other matters are all factors that can impact service quality.

Staff has had significant experience with the service quality history of GMO over the past several years as addressed in the Staff Acquisition Report, Case No. EM-2007-0374. As a result of Aquila's 2004 rate case, Case No. ER-2004-0034, Staff began receiving monthly reporting of a number of Aquila's service quality metrics. KCPL is required to provide quarterly reporting of monthly metrics to Staff as part of its regulatory plan which the Commission approved in Case No. EO-2005-0329.

Service quality metrics can be used to determine and monitor the level of customer service that utilities are providing to their customers and help ensure that customers are receiving an acceptable level of service in those areas. Some aspects of service quality, however, do not readily lend themselves to indicators. Examples include the consistent application of credit and collection practices, detection and correction of billing errors and the effective training of customer service associates or representatives to ensure the relaying of accurate and consistent information to customers, as well as their courteous treatment.

Call centers perform a critical function in utility operations as they provide the primary means for customers to contact their utility. Customers may require contact with their utilities for numerous reasons including: to report emergencies and service outages; requests to initiate, discontinue, transfer or restore service; questions regarding customer bills; usage; delinquent accounts; and to make payment arrangements. During the winter months when the Commission's Cold Weather Rule is in effect, call centers may actually be a "life line" for some customers who are nearing service disconnection and need to make payment arrangements. It is always imperative, but particularly so during emergencies and in times of unusually cold and hot weather, that call centers function in an effective manner. As utilities have closed business offices that once accommodated walk-in traffic and provided customers with a utility presence in their community, the role of the call center has become increasingly important as a primary point of contact for utility customers.

Staff and the Office of the Public Counsel presently receive monthly call center reports from GMO which include: calls offered (or call volume coming into the call center), call center staffing, average speed of answer (the number of seconds a caller waits before his/her call is answered by a representative), abandoned call rate (the percentage of calls that are abandoned by customers prior to being answered by representatives) and service levels (a percentage of calls answered within a specified period of seconds). Reports also include estimated meter reading data, as well as reliability metrics, which measure system outages. Before Great Plains Energy

Incorporated acquired Aquila, Aquila's call center performance had improved significantly in recent years from where it had been, particularly in the years 2002 and 2003.

GMO customers have experienced a decline in customer service levels since the consolidation of GMO's operations with those of KCPL, and the decline in the level of customer service can be seen in GMO's monthly call center statistics that are reported to the Commission's Engineering and Management Services Department. GMO experienced an increase in its abandoned call rate (ACR) to 18.1% from July 14, 2008 to July 31, 2008. It also experienced a significant increase in its average speed of answer (ASA) to 190 seconds.

The Company informed Staff that its call center performance in July 2008 was the result of a call center technological problem that included four of seven trunk lines being mapped incorrectly. When a customer notified Staff that he had tried to reach the Company "42 times" through its call center and had been unsuccessful, Staff contacted appropriate Company personnel on July 31, 2008 to indicate that 1) Staff had received customer communication indicating a problem, 2) to investigate the cause of the performance problem, and 3) to discuss the Company's plan for corrective action. KCPL representatives indicated it had corrected the trunk mapping issue and began a process of rechecking the system to verify that calls were not being dropped. Customers whose calls had been dropped heard silence when they attempted to dial the Company.

Three year historical call center performance for both GMO and KCPL is presented in the tables on the following page:

Abandoned Call Rate					
	GMO				
	2006	2007	2008		
January	4.8	1.1	1.8		
February	3.4	1.2	1.7		
March	1.6	1.2	0.8		
April	1.6	1.6	1		
May	7.2	1.5	1.6		
June	3.6	1.4	1.7	Consolidation	
July	0.8	1.5		July 1-13	July 14-31
August	1.3	1.5	7.8	1.9	18.1
September	1.3	1.5	6.2		
October	1.5	3.2	4		
November	0.5	2	3.2		
December	0.7	2.4	4.6		

Source: GMO and KCPL Service Quality Reports provided to Staff and the Office of the Public Counsel as a result of Case Nos. EO-2005-0329 and ER-2004-0034.

Abandoned Call Rate					
	KCPL				
	2006	2007	2008		
January	1.95	2.62	4.18		
February	2.00	3.37	5.68		
March	6.23	3.61	2.93		
April	5.18	4.69	1.34		
May	4.60	2.72	6.86		
June	3.23	2.38	5.00	Consolidation	
July	5.92	4.35		July 1-13	July 14-31
August	3.70	6.15	7.80	6.76	18.1
September	1.96	7.30	6.20		
October	2.20	10.10	4.00		
November	3.00	4.54	3.20		
December	1.31	6.40	4.60		

Source: GMO and KCPL Service Quality Reports provided to Staff and the Office of the Public Counsel as a result of Case Nos. EO-2005-0329 and ER-2004-0034.

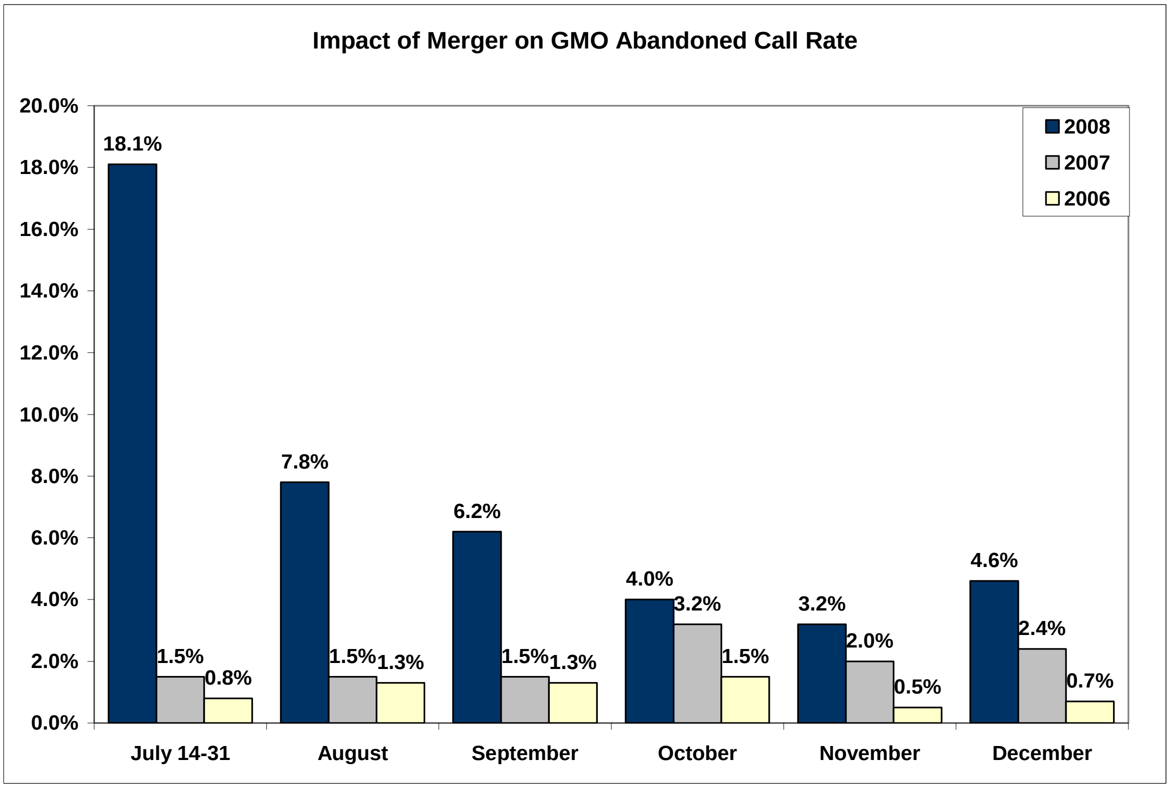
Average Speed of Answer					
	GMO				
	2006	2007	2008	Consolidation	
January	54	7	19		
February	40	9	17		
March	18	12	6		
April	18	16	12		
May	78	16	17		
June	39	14	19	Consolidation	
July	9	18		July 1-13	July 14-31
August	14	17	72	22	190
September	14	17	62		
October	14	42	36		
November	3	24	24		
December	5	21	31		

Source: GMO and KCPL Service Quality Reports provided to Staff and the Office of the Public Counsel as a result of Case Nos. EO-2005-0329 and ER-2004-0034.

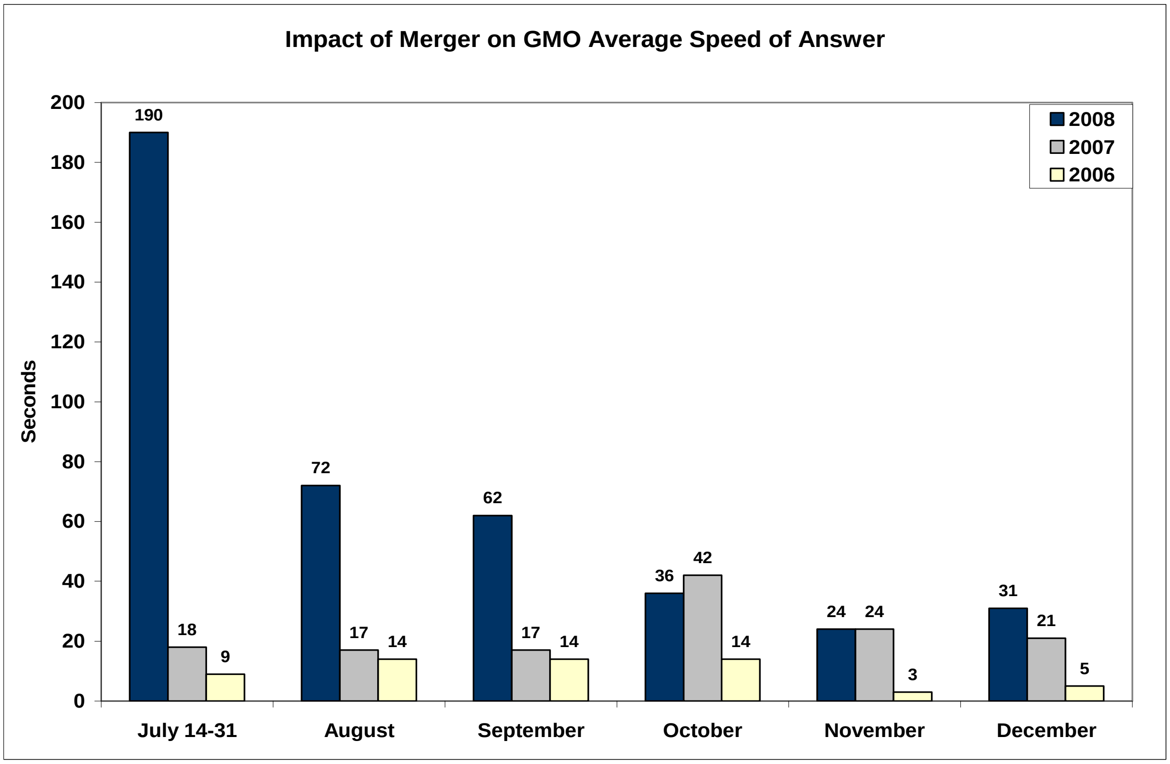
Average Speed of Answer					
	KCPL				
	2006	2007	2008		
January	26	18	39		
February	30	30	56		
March	46	31	22		
April	38	40	15		
May	32	24	59		
June	28	18	42	Consolidation	
July	45	40		July 1-13	July 14-31
August	34	55	72	58	190
September	23	73	62		
October	21	104	36		
November	30	48	24		
December	14	59	31		

Source: GMO and KCPL Service Quality Reports provided to Staff and the Office of the Public Counsel as a result of Case Nos. EO-2005-0329 and ER-2004-0034.

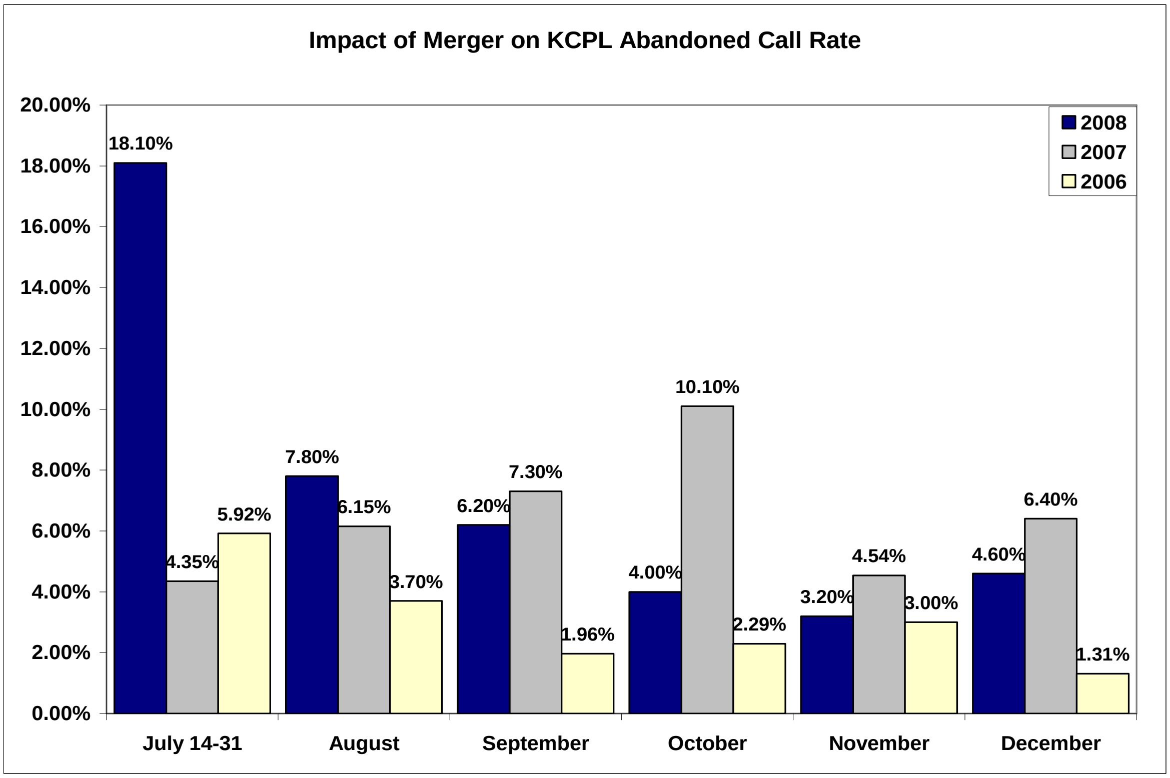
The following four graphs present the impact the merger has had on the ACR and ASA as compared to previous years for selected months for GMO and KCPL. With the exception of the July 2008 ASA, and KCPL's August 2008 ACR,, KCPL's call center performance metrics has improved over the previous year.



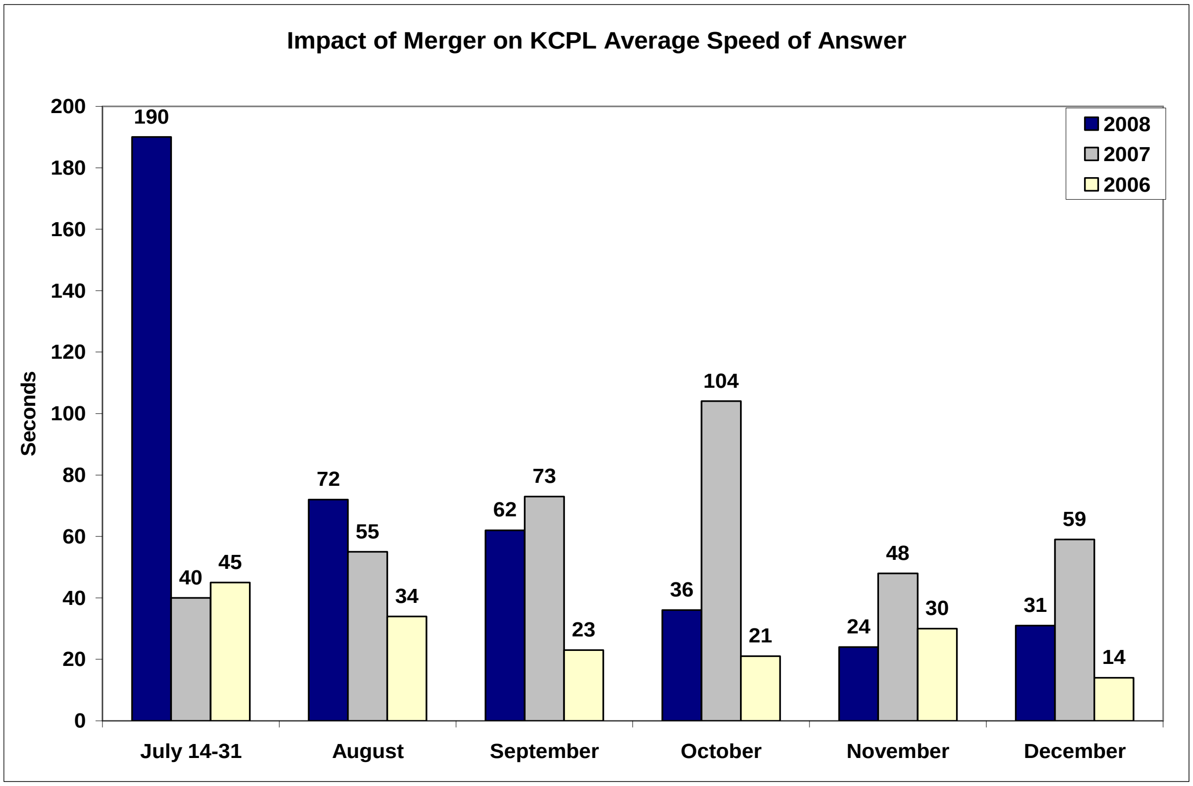
Source: GMO and KCPL Service Quality Reports provided to Staff and the Office of the Public Counsel as a result of Case Nos. EO-2005-0329 and ER-2004-0034.



Source: GMO and KCPL Service Quality Reports provided to Staff and the Office of the Public Counsel as a result of Case Nos. EO-2005-0329 and ER-2004-0034.



Source: GMO and KCPL Service Quality Reports provided to Staff and the Office of the Public Counsel as a result of Case Nos. EO-2005-0329 and ER-2004-0034.



Source: GMO and KCPL Service Quality Reports provided to Staff and the Office of the Public Counsel as a result of Case Nos. EO-2005-0329 and ER-2004-0034.

Staffing Levels

At the time of the merger, GMO and KCPL indicated to Staff that there would be no net reductions in call center staffing from either utility. At that time, the Missouri jurisdictional allocated headcount of GMO's call center was 49 and KCPL's was approximately 70. Because pre-consolidation call volumes did not segregate Missouri customer calls, Staff and KCPL cannot calculate whether or not an actual increase in call center volume occurred since the consolidation. KCPL representatives have indicated their opinion that call volumes did rise somewhat after the consolidation. KCPL and GMO call center personnel currently use the same customer information systems each utility used prior to the consolidation.

Based upon GMO and KCPL January 2009 service quality reporting to Staff, the 119 employee number is consistent with pre-consolidation headcount numbers. KCPL indicates it maintained eight temporary and two transitional staff through the end of

January 2009 to assist it in the transition of its call centers. Also, in July 2008, the staff inquired into the KCPL call center's decline in performance, and the Company indicated it had lost two call center representatives to another Kansas City utility.

Commission Complaints

One additional indication of service quality that Staff reviews is complaints per thousand customers. Staff has calculated complaints per thousand for 2007 and 2008 from both GMO and KCPL residential customers, as seen in the tables on the following page.

2007	Customers*	MOPSC Complaints	Complaints Per Thousand Customers
KCPL	239,000	217	.91
GMO	270,000	206	.76

Source: MoPSC Consumer Services Department
*Approximate number of residential customers.

2008	Customers*	MOPSC Complaints	Complaints Per Thousand Customers
KCPL	239,000	320	1.3
GMO	274,000	119	.43

Source: MoPSC Consumer Services Department
*Approximate number of residential customers.

GMO's 2008 Commission complaints actually decreased from where they were in 2007; however, KCPL residential customer complaints increased substantially.

Quarterly Meetings

The Commission's July 1, 2008 order in EM-2007-0374 required that KCPL and GMO engage in quarterly customer service performance reviews with the Commission's Staff.[17] On October 24, 2008, KCPL, GMO and Staff held its first quarterly meeting at the Company's Raytown, Missouri office. The meeting included presentations by GMO, along with periods of questions and answers.

[17] Report and Order, Case No. EM-2007-0374, July 1, 2008, page 282; item 6 d.

The second quarterly meeting was held February 6th, 2009, at the Missouri Public Service Commission's offices in Jefferson City, Missouri.

Summary and Staff's Recommendation

Service levels for GMO service territories decreased soon after the consolidation of GMO and KCPL operations, as displayed in monthly call center performance statistics reported to Engineering and Management Services Department Staff; however, call center performance statistics have moderated since the initial consolidation of operations. Staff intends to continue monitoring GMO and KCPL performance closely as well as meet with the utility on a quarterly basis to discuss service quality, as was ordered. in Case No. EM-2007-0374.

Staff Expert: Lisa A. Kremer

APPENDICES

Appendix 1: Staff Credentials

Appendix 2: David Murray Schedules and Attachments

Appendix 3: Manisha Lahanpal Schedules

Appendix 4: Walter Cecil Schedule

Appendix 5: Rosella Schad Schedules

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power and Light Company for Approval to Make Certain Changes in its Charges for Electric Service To Continue the Implementation of Its Regulatory Plan.	)))))	Case No. ER-2009-0089

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 pages 80-81 ; 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 10th day of February, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power and Light Company for Approval to Make Certain Changes in its Charges for Electric Service To Continue the Implementation of Its Regulatory Plan.	)))))	Case No. ER-2009-0089

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 pages 77, 121-122; 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 11th day of February 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power and Light Company for Approval to Make Certain Changes in its Charges for Electric Service To Continue the Implementation of Its Regulatory Plan.	)))))	Case No. ER-2009-0089

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 pages 74-75, 78 and 81 ; 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 10th day of February, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power and Light Company for Approval to Make Certain Changes in its Charges for Electric Service To Continue the Implementation of Its Regulatory Plan.	)))))	Case No. ER-2009-0089

AFFIDAVIT OF KOFI AGYENIM BOATENG, CPA, CIA

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Kofi Agyenim Boateng, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 61-62, 71-72, 112-113 and 116-117; 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.

Kofi Agyenim Boateng

Subscribed and sworn to before me this 10th day of February, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power and Light Company for Approval to Make Certain Changes in its Charges for Electric Service To Continue the Implementation of Its Regulatory Plan.	)))))	Case No. ER-2009-0089

AFFIDAVIT OF WALT CECIL

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Walt Cecil, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 57 - 58; 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.

Walt Cecil

Walt Cecil

Subscribed and sworn to before me this 10th day of February, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power and Light Company for Approval to Make Certain Changes in its Charges for Electric Service To Continue the Implementation of Its Regulatory Plan.	)))))	Case No. ER-2009-0089

AFFIDAVIT OF V. WILLIAM HARRIS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

V. William Harris, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 51-52, 65-71, 72-74 and 75-77; 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.

V. William Harris

V. William Harris

Subscribed and sworn to before me this 10th day of February, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power and Light Company for Approval to Make Certain Changes in its Charges for Electric Service To Continue the Implementation of Its Regulatory Plan.	)))))	Case No. ER-2009-0089

AFFIDAVIT OF PAUL R. HARRISON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Paul R. Harrison, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 53-54, 87-90, 91, 104-109, 118 and 134-140; 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.

Paul R. Harrison
Paul R. Harrison

Subscribed and sworn to before me this 10th day of February, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power and Light Company for Approval to Make Certain Changes in its Charges for Electric Service To Continue the Implementation of Its Regulatory Plan.	)))))	Case No. ER-2009-0089

AFFIDAVIT OF KAREN HERRINGTON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Karen Herrington, of lawful age, on his oath states: that she has participated in the preparation of the foregoing Staff Report in pages 45-48, 98-101, 109-112, 117-118 and 122-125; 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.

Karen Herrington

Karen Herrington

Subscribed and sworn to before me this 10th day of February, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power and Light Company for Approval to Make Certain Changes in its Charges for Electric Service To Continue the Implementation of Its Regulatory Plan.	)))))	Case No. ER-2009-0089

AFFIDAVIT OF CHARLES R. HYNEMAN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Charles R. Hyneman, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 90-94, 101-104, 118-121, 125-131 and 145-152; 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.

Charles R. Hyneman

Subscribed and sworn to before me this 10th day of February, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
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D. Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

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AFFIDAVIT OF LISA A. KREMER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Lisa A. Kremer, of lawful age, on his oath states: that she has participated in the preparation of the foregoing Staff Report in pages 152 - 162; 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.

Lisa A. Kremer

Lisa A. Kremer

Subscribed and sworn to before me this 10th day of February, 2009.

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Notary Public - Notary Seal
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AFFIDAVIT OF MANISHA LAKHANPAL

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Manisha Lakhanpal, of lawful age, on his oath states: that she has participated in the preparation of the foregoing Staff Report in pages 54-57, 58-60 and 62-64; 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 10th day of February, 2009.

D. SUZIE MANKIN
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D Suzie Mankin
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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 pages 78-80; 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 10th day of February, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
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BEFORE THE PUBLIC SERVICE COMMISSION

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AFFIDAVIT OF ADAM C. McKINNIE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Adam C. McKinnie, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 119 - 120; 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.

Adam C. McKinnie

Subscribed and sworn to before me this 10th day of February, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

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In the Matter of the Application of Kansas City Power and Light Company for Approval to Make Certain Changes in its Charges for Electric Service To Continue the Implementation of Its Regulatory Plan.	)))))	Case No. ER-2009-0089

AFFIDAVIT OF KEITH A. MAJORS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Keith A. Majors, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 81-86 and 94-98; 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.

Keith A. Majors
Keith A. Majors

Subscribed and sworn to before me this 10th day of February 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
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D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

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AFFIDAVIT OF DAVID MURRAY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

David Murray, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 8-44; 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 Murray

David Murray

Subscribed and sworn to before me this 10th day of February, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071

D. Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power and Light Company for Approval to Make Certain Changes in its Charges for Electric Service To Continue the Implementation of Its Regulatory Plan.	)))))	Case No. ER-2009-0089

AFFIDAVIT OF BRET G. PRENGER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Bret G. Prenger, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 48-51, 52-53, 113-115 and 131-134 ; 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.

Bret G. Prenger

Bret G. Prenger

Subscribed and sworn to before me this 10th day of February, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
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D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

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AFFIDAVIT OF ROSELLA L. SCHAD, PE, CPA

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Rosella L. Schad, of lawful age, on his oath states: that she has participated in the preparation of the foregoing Staff Report in pages 134-135; 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 PE CPA
Rosella L. Schad

Subscribed and sworn to before me this 10th day of February, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071

D. Suzie Mankin
Notary Public