MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

COST OF SERVICE

Great Plains Energy, Incorporated
GREATER MISSOURI OPERATIONS
GMO-MPS AND GMO-L&P ELECTRIC

CASE NO. ER-2009-0090

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

Jefferson City, Missouri
February 13, 2009

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COST OF SERVICE REPORT

TABLE OF CONTENTS

COST-OF-SERVICE REPORT

I. Background of Great Plains Energy and KCP&L - Greater Missouri Operations Company

KCP&L Greater Missouri Operations Company ("GMO" or "the Company") is a corporation duly organized and existing under the laws of the State of Missouri. GMO is a regulated public utility operating in the state of Missouri. It also provides wholesale electricity to several municipal customers under the jurisdiction of the Federal Energy Regulatory Commission. GMO distributes and sells electric service to the public in its certificated areas in 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. GMO is wholly owned by Great Plains Energy ("GPE") and an affiliate of Kansas Power & Light Company ("KCPL")

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 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. Prior to the July 14, 2008 acquisition by GPE, GMO was formerly known as Aquila, Inc. and before that UtiliCorp United, Inc.

In this report, depending on the name it had at the pertinent time what is now named KCP&L Greater Missouri Operations Company may be referred to as GMO, Aquila or UtiliCorp. GPE acquired Aquila in 2008 after the Missouri Public Service Commission ("Commission"), in Case No. EM-2007-0374, in a *Report and Order* made effective July 11, 2008, approved the joint application of GPE, KCPL, and Aquila for authority to engage in a series of transactions where GPE would acquire Aquila after it divested all of its operations except its Missouri electric and steam operations, and 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. After GPE acquired Aquila the Commission by an order effective August 8, 2008 entered in Case No. EN-2009-0015, "recognize[d] the name change of Aquila, Inc., dba Aquila Networks – L&P and Aquila, Inc. dba Aquila Networks – MPS to Aquila, Inc., dba KCP&L Greater Missouri Operations Company and by a *Report and Order* effective December 3, 2008, entered in Case No. EN-2009-0164, recognized the name change of Aquila, Inc., d/b/a KCP&L Greater Missouri Operations Company to KCP&L Greater Missouri Operations Company.

The part of GMO's service territory in and about St. Joseph, Missouri has different rates than the remainder of its service territory, which is about Kansas City, Missouri. For rate setting purposes a revenue requirement must be developed for each and also for each utility service provided there. For GMO that means two electric revenue requirements and one steam revenue requirement. Before GPE acquired Aquila, with Commission authorization used the name Aquila Networks – L&P for its regulated operations in and about St. Joseph and Aquila Networks – MPS for the remainder of its regulated Missouri operations. While GMO no longer uses the names Aquila Networks – L&P or Aquila Networks – MPS, because of the need to develop three different revenue requirements in this case based on operations associated with those names in the past, and GMO having provided no better way to refer to them, Staff will use "GMO L&P" or "L&P" when referring to GMO's regulated operations that were formerly referred to as Aquila Networks – L&P and "GMO MPS" or "MPS" when referring to GMO's regulated operations that were formerly referred to as Aquila Networks – MPS.

II. Executive Summary

Please summarize the Staff's filing.

Curt Wells, of the Commission's Utility Operations Division, and Cary Featherstone, of the Commission's Utility Services Division sponsor Staff's Cost of Service Report in this proceeding that is being filed concurrently with testimony of Mr. Wells and Mr. Featherstone. 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.

This is 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.

Staff recommends that GMO be permitted to increase its electric rates to recover an additional $46 million per year for MPS and $22.8 million per year for L&P. Each of these amounts includes substantial amounts 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.

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

- Rate of Return proposed by Staff for both MPS and L&P electric
- Plant upgrades for environmental costs and maintenance costs for Sibley and Jeffrey Energy Center through the allowance for known changes which will effect MPS electric
- Plant upgrades for environmental costs and maintenance costs for Iatan 1 through the allowance for known changes which will effect L&P electric
- Fuel costs and purchased power costs for both MPS and L&P electric
- Off-system sales in the firm and non-firm bulk power markets for MPS
- Costs relating to the Commission's new rules on vegetation management and infrastructure inspection and repairs through the allowance for know changes for both MPS and L&P electric
- Pension costs for both MPS and L&P electric
- Jurisdictional Allocations for MPS
- Acquisition savings and transition costs for both MPS and L&P electric

III. KCP&L Greater Missouri Operations Company's Rate Case Filing

GMO 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.

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. GMO proposes a rate of return on equity of 10.75% applied to the 53.82% equity capital structure for GPE.

KCPL also 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 proposes a rate of return on equity of 10.75% applied to the 53.82% equity capital structure for GPE.

A. Test Year

The test year being used in this case, as well as the KCPL case, 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 8.03 percent to 8.54 percent for KCPL Greater Missouri Operations (GMO). 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 GMO's September 30, 2008, common equity ratio of 51.03 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 6.75 percent is a proxy cost of long-term debt based on The Empire District Electric Company's embedded cost of debt as of the true-up period, February 29, 2008, in its last rate case, Case No. ER-2008-0093. Staff will explain its detailed rationale later in this segment of the Report as to why it believes this is an appropriate proxy for a fair and reasonable rate of return for GMO.

Staff's capital structure recommendation is based on GPE's consolidated capital structure, exclusive of the preferred stock and short-term debt, as of September 30, 2008. Schedule 8, contained within Appendix 2 attached to the Report, presents the recommended common equity ratio and long-term debt ratio for GMO's ratemaking capital structure.

This capital structure consists of 51.03 percent common stock equity and 48.97 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

[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).

> 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 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

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[2] ***Bluefield,*** *supra,* 262 U.S. at 692-93, 43 S.Ct. at 679, 67 L.Ed. at 1182-1183.
[3] ***Hope,*** *supra*, 320 U.S. at 603, 64 S.Ct. at 288, 88 L.Ed. at 345.

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.

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.

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[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.

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 GMO. 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 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;

[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.

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 GMO 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 the Staff used for this case is GPE's capital structure on a consolidated basis, exclusive of preferred stock and short-term debt, 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 for long-term debt and common equity. The resulting ratemaking capital structure consists of 51.03 percent common stock equity and 48.97 percent long-term debt.

Staff chose to remove the GPE's preferred stock from the capital structure because this is an embedded cost and Staff is not proposing the consolidation of embedded costs for purposes of this case. Consequently, because GPE's preferred stock and debt were issued before the acquisition of the Aquila Missouri electric utility properties, Staff believes it is appropriate to exclude the preferred capital from its recommended rate of return for GMO.

It is appropriate to use GPE's capital structure, exclusive of preferred stock and short-term debt, for GMO's ratemaking capital structure because this represents the current financial risk associated with GMO's operations. GMO's credit rating is based on the consolidated credit profile of GPE. For example, in S&P's September 19, 2008 research report on GMO, S&P analyzes GPE's consolidated financial ratios when providing its opinion on GMO's creditworthiness. In fact, GPE did not file separate GMO financial statements with the SEC when it filed its Form 10Q Filing for September 30, 2008. GMO's financial results are embedded in GPE's consolidated financial statements.

Although GPE's capital structure will be that analyzed by investors going forward when determining a required yield on debt funds used by GPE for GMO's operations, it is the capital structures of the companies that previously owned GMO's electric utility operations that drove the required return on the debt contained in GMO's current embedded cost of long-term debt. In fact, some of this debt wasn't even issued under Aquila's ownership. Some of the debt assigned to GMO's L&P division was issued while these operations were a part of the stand-alone, publicly-traded entity, St. Joseph Light and Power Company (SJL&P). Therefore, GMO is carrying debt issuances that were associated with business and financial risks that were in effect at the time SJL&P issued this debt. One could argue that the ratemaking capital structure for the instant rate case should take both Aquila's and SJL&P's capital structures into consideration when evaluating the appropriateness of Staff's proposed ratemaking capital structure. However, the problem with this type of evaluation is not only would one be evaluating capital structures for two companies, it would be evaluating capital structures for two companies during different capital, business and economic conditions. Ideally, a company will adjust its capital structure to achieve the lowest cost of capital for the environment in which they operate. Also, one has to realize that because the recommended ROE is based on an estimate of the current cost of common equity, it is important to use a current capital structure that reflects the current amount of common equity in the capital structure.

Notwithstanding the above, Staff also notes that the ratemaking capital structure used in Aquila's last rate case, Case No. ER-2007-0004, was fairly close to Staff's proposed capital structure in this case. Staff's rate of return recommendation in that case was based on capital structure containing 47.5 percent equity and 52.5 percent long-term debt. However, Staff also notes that Aquila's historical capital structures had on average been more leveraged than in the most recent two years prior to GPE's acquisition of the GMO properties (see Schedule 6-2).

Although, GPE's overall risk profile has been impacted by its divestiture of Strategic Energy and its acquisition of the GMO properties, 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, the financial risk of GPE's consolidated capital structure 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 Aquila'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 the acquisition. Also, due to the timing of GPE's announced 50 percent dividend reduction made on February 10, 2009, Staff was not able to reflect this new information in this cost of service report or in the cost of service report filed in the KCPL rate case, Case No. ER-2009-0089. Regardless, Staff did not believe a GPE company-specific cost of common equity estimate should be given any weight because of the effect that the acquisition of the GMO properties may have had on GPE's stock price. However, the recent action by GPE solidifies that investors may have considered GPE's current dividend to be at risk of being reduced because GPE's dividend yield was quite high at the time Staff performed its analysis.

It is also worthy to note that Staff's proposed ratemaking capital structure in this case is similar to The Empire District Electric Company's common equity ratio of 50.82 percent as of the test year in its most recent rate case, Case No. ER-2008-0093. Staff believes this supports using a common equity ratio of around 50 percent for GMO's electric utility properties. However, careful consideration should be given to the cost of debt used with this capital structure.

F. Embedded Cost of Debt

In the prior Aquila rate case, Case No. ER-2007-0004, Staff witness David Parcell[7] accepted the costs of debt used by Aquila for its Missouri electric utility divisions. Staff witness Parcell did not accept the capital assignment process or the methodology used to make adjustments to the cost of debt, he simply accepted the overall estimate. In Aquila's two rate cases prior to Aquila's most recent case, Case Nos. ER-2005-0436 and ER-2004-0034, Staff witness Murray used Aquila's consolidated embedded cost of debt, but made adjustments to this debt. In Case No. ER-2004-0034, Staff simply excluded the debt that was issued after Aquila had its corporate credit rating downgraded to below investment grade. In Case No. ER-2005-0436, Staff used the cost of an Empire debt issuance that was issued around the same time as the Aquila non-investment grade debt issuance and included this with the rest of Aquila's debt issued prior to its credit rating being downgraded to "junk" status. Aquila's failed

[7] Staff hired a consultant in the last rate case

non-regulated investments have caused the need for both the company and other parties to make judgments on what the cost of debt might have been if MPS and L&P had been owned by a company with at least an a BBB credit rating. As time has passed and ownership structures have changed, the embedded cost of debt for MPS and L&P has become even less based on reality.

As a result of the above, Staff recommends the use of a hypothetical embedded cost of long-term debt for GMO. Staff proposes the use of The Empire District Electric Company's (Empire) embedded cost of long-term debt from its last rate case, Case No. ER-2008-0093 as of the true-up date, February 29, 2008. This embedded cost of long-term debt was 6.75 percent. Staff believes the use of Empire's embedded cost of debt is appropriate because the risk profile of Empire and GMO are fairly similar, Empire's operations are predominately regulated operations, most of which are confined to Missouri, and Empire's most recent ratemaking capital structure is similar to that of GMO's parent company, GPE.

G. Cost of Common Equity

In order to estimate the cost of common equity for GMO, Staff performed a comparable company cost of common equity analysis of eleven electric utility companies. Staff estimated GMO'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 GMO:

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 GMO'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, GMO. 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. Therefore, Staff chose to give full weight to the analysts' earning growth estimates for the

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[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.

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 in the October 2004 issue of *Public Utilities Fortnightly,* "The Dividend Yield Trap," regulated

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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.*

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 GMO's credit rating is similar to that of the proxy group. This implies that the risk profile of the proxy group and GMO 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 (now 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 GMO's witness' estimated cost of common equity in this case and in past KCPL and Aquila 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 GMO 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 8.03 to 8.54 percent was developed for GMO's Missouri electric utility operations (see Schedule 21). This rate was calculated by applying an embedded cost of long-term debt of 6.75 percent and a cost of common equity range of 9.25 percent to 10.25 percent to a capital structure consisting of 51.03 percent common equity and 48.97 percent long-term debt. Therefore, from a financial risk/return prospective, as Staff suggested earlier, Staff recommends that GMO's electric utility operations be allowed to earn a return on its rate base in the range of 8.03 percent to 8.54 percent.

Through Staff's analysis, it believes that it has developed a fair and reasonable return, which, when applied to GMO's jurisdictional rate base, will allow GMO 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 the plant in service (plant) and accumulated depreciation reserve (reserve) balances based on the actual booked amounts as 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 time of the true-up, adjustments to the plant will be updated to include plant additions placed in service during the period of September 30, 2008 through March 31, 2009, and the depreciation reserve balances related to those additions. These additions must be providing service to the customers before the plant is reflected in rates. During the analysis of the Company's plant reserve balances, Staff found GMO 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 Company 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 Company. 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 Company 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.

Cash Working Capital Schedule 8 identifies the amount of cash working capital that has been determined using a 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.

Prior to the KCP&L's acquisition of Aquila Inc, Aquila Inc. had developed financial difficulties resulting in third party lenders terminating their account receivables contracts. As a result, rate payers did not receive the benefits for selling the accounts receivable. Failure to sell a portion of their accounts receivable resulted in a longer revenue lag. This revenue lag was reduced to reflect the number of days had the Company sold a portion of their accounts receivables. The change in the revenue lag can be found on Schedule 8. The accounts receivable program will be discussed in greater detail infra *Accounts Receivables Bank Fees*.

GMO performed a lead-lag study using a method very similar to that used by Staff in previous cases. Staff did not perform a complete, independent CWC analysis in this case, instead relying on the calculations made by the GMO entities and Staff in previous cases.

However, Staff identified a problem with the KCPL Gross Receipt Tax calculation and determined that it was appropriate to more closely analyze that calculation in the lead-lag study of the GMO entities.

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

Staff reviewed the city ordinances for the Gross Receipt Tax (GRT) to obtain a better understanding of how the tax was imposed and how it was collected. Staff found the tax was based on previous revenues on a semi-annual, quarterly, or a monthly basis. Staff has determined that all municipalities served by the GMO entities require that the GRT be remitted to those taxing authorities after the GRT amounts are assessed, billed to GMO's customers and collected by the Company. Since the Company remits the GRT to the taxing authorities after it collects it from its electric customers, these taxes are paid in the 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 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. As a result of the analysis, Staff determined the GMO entities use the same methodology as Staff and treat the revenues as paid in the arrears. The calculations for the gross receipts taxes are reflected in the CWC schedule (Schedule 8) as Lines 25 for GMO-MPS and Line 23 for GMO-L&P.

Staff Expert: Karen Herrington

C. Prepayments

Prepayments are investments a utility makes in assets prior to their use in providing utility service and are reflected in rate base. Staff included amounts for prepayments that MPS and L&P require to provide electric utility service to their customers. Staff examined the electric prepayment account balances for MPS and L&P 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 the MPS and L&P electric rate-bases 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. Also, included in these monthly prepayment averages are balances for the ECORP common plant account that was allocated between MPS and L&P accordingly. ECORP is a cost center that collects the common assets and expenses of GMO (MPS, L&P electric and L&P steam). (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 a utility and are included in 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 MPS's Missouri jurisdictional customer deposits. The same methodology, a 13-month average, was used to calculate the customer deposits for L&P electric as well. Rate base is reduced because these funds are cost-free funds received by MPS and L&P.

In addition to the amount reflected in the MPS and L&P rate bases for customer deposits, an amount for interest on customer deposits has been included as an adjustment to the income statement under Account 903 for each. (Accounting Schedule 2)

Staff Expert: Bret G. Prenger

E. Customer Advances

Customer advances are funds typically provided by developers to a utility to build electric infrastructure in areas that have the potential for future development. The amount of customer advances reflected on Accounting Schedule 2, Rate Base represents the September 30, 2008 ending monthly balance of MPS' jurisdictional contributions. Staff followed this approach with MPS because the account balances fluctuated significantly. Staff followed the same methodology for L&P electric, using the September 30, 2008 ending monthly balance. Like customer deposits, customer advances are reflected as an offset to rate base because they represent cost-free funds to the utility. (Accounting Schedule 2)

Staff Expert: Bret G. Prenger

F. Customer Deposits – Interest Expense

Amounts of interest on customer deposits have been included as adjustments to the Income Statement - Schedule 9 for both MPS and the electric operation of L&P. Staff calculated interest for customer deposits consistent with the levels of customer deposits reflected for MPS and L&P in Rate Base, Schedule 2, (*see* discussion in the Rate Base section of this report for customer deposits included in rate base). The interest rate used was the most current prime interest rate published in the Wall Street Journal (7.50%), plus 1% for a total rate of 8.50%. Adjustments E-129.2 (MPS) and E-132.2 (Electric) is being made to include these levels of interest expense for customer deposits for MPS and for L&P.

Staff Expert: Bret G. Prenger

G. Fuel Inventories

1. Coal Inventory

The Staff included in the rate base of MPS and L&P an amount for coal inventory based on results obtained from the Staff's production cost model (fuel model). Among other things, the 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, the 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 GMO, the Staff divided the annual tons of coal burned from the fuel model by 365 days to calculate an average daily burn by unit. The 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 base-mat coal. Base-mat coal is the bottom portion of the coal pile that is not fully usable as fuel due to contamination by soil, clay and other contaminates. The 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 for the units of MPS and the units of L&P and the aggregated amount for MPS and L&P separately multiplied by the Staff's energy jurisdictional allocation factor to arrive at the coal inventory amount shown as coal inventory in Rate Base Schedule 2.

2. Oil and Other Fuel Inventories

The Staff used 13-month averages to determine the inventory levels for oil and other fuel inventories consistent with how GMO determined its inventory levels for these items for MPS and L&P.

A 13-month average inventory reflects a utility'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 a utility'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. MPS Accounting Schedule 2 - Rate Base reflects the Staff's inventory levels for coal, oil, propane, tires and bio fuel for MPS. L&P Accounting Schedule 2 - reflects the Staff's inventory levels for coal, oil, tires and fuel stock for L&P.

Staff Expert: V. William Harris

H. Material and Supplies

Materials and supplies (M&S) represent investments 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 MPS and L&P to maintain their production facilities and electric system. Staff reviewed the monthly balances for materials and supplies for MPS over the last several years, and because there was a noticeable decreasing trend in accounts 154 and 163, Staff included the September 30, 2008 monthly ending account balances for these accounts in MPS's rate base.

For the electric operation of L&P Staff decided that because of the decreasing balances in Account 154, the September 30, 2008 ending monthly balance was the most accurate way to measure the ongoing investment level in this asset. For account 163, there was a constant fluctuation in the months reviewed, so a 13-month average balance was used.

(Accounting Schedule 2)

Staff Expert: Bret G. Prenger

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

Financial Accounting Standard (FAS) 87 is the accrual accounting method for calculating pension cost for financial reporting purposes. However, for Kansas City Power & Light Greater Missouri Operation's or the former Aquila Networks Missouri Public Service and St. Joseph Light and Power regulated entities, MPS and L&P, both the Staff and the Company recommend continuation of the settlement agreement originally reached in Case No. ER-2004-0034 and continued in Case No. ER-2005-0436 and Case No. ER-2007-0004. The settlement agreement provides for the use of the minimum contributions required under the Employee Retirement Income Security Act (ERISA) for determining MPS's and L&P's pension cost for ratemaking purposes. ERISA was established by federal statute in 1976 and is intended to ensure the funding of defined benefit pension plans in the United States.

FAS 87 is an accrual accounting method required by the accounting profession under Generally Accepted Accounting Procedures (GAAP) for financial reporting purposes. Under FAS 87 a company accrues (expenses) an employee's earned pension benefits over the service life of the employee. The total obligation to the employee for pension benefits is accumulated annually until retirement in the Accumulated Benefit Obligation (ABO). Both financial statement expense recognition under FAS 87 and the funding requirements under ERISA are based upon the same pension plan obligation to employees enrolled in the plan. While different assumptions are used for the timing of pension cost recognition during the service life of the employee under FAS 87 and ERISA, both FAS 87 and ERISA are intended to address the same total ABO by the employee's retirement date. The Staff has historically used both FAS 87 and the ERISA minimum contributions for determining pension cost for ratemaking purposes.

In MPS’s and L&P’s last general electric rate case, Case No. ER-2007-0004, the parties entered into a settlement agreement to use the provisions that were established in MPS’s and L&P’s previous rate case, Case No. ER-2005-0436, which included the following provisions:

1) A Prepaid Pension Asset representing negative pension cost flowed through in rates in prior cases was agreed to in the stipulation and agreement in Case No. ER-2004-0034. This Prepaid Pension Asset is being amortized to cost of service over 5 1/2 years for the MPS division and 9.25 years for the L&P division starting with the effective date of rates established in Case No. ER-2004-0034, April 22, 2004. The unamortized balance is included in rate base for the MPS and L&P divisions. This treatment was continued in the stipulation and agreement in Case No. ER-2005-0436 and ER-2007-0004.

2) Annual pension cost reflected in cost of service is to be based upon MPS and L&P’s ERISA minimum contributions requirements.

3) A tracking mechanism tracks the difference between the pension cost included in rates and MPS and L&P’s actual pension fund contributions during the period that existing rates are in effect. The resulting regulatory asset (actual fund contributions exceed rate recovery) and/or regulatory liability (actual fund contributions are less than rate recovery) are included in rate base and amortized to cost of service over 5 years.

The rate base amounts and cost of service adjustments the Staff has reflected in this current case, Case No. ER-2009-0090, are based on continuation of the agreements reached in the stipulation and agreements in Case Nos. ER-2004-0034, ER-2005-0436 and ER-2007-0004.

The Staffs rate base includes a Missouri jurisdictional balance of $2,233,545 and $16,121,101 for the MPS and L&P divisions prepaid pension asset unrecovered balance, respectively, as of September 30, 2008. This amount will be updated through March 31, 2009, in the true-up audit for this case. As of September 30, 2008, MPS and L&P divisions have collected $4,344,194 and $8,748, respectively, more in rates than the actual contributions made to the pension fund. This regulatory liability is reflected as a reduction to MPS's and L&P's rate base and amortized as a reduction to pension cost over 5 years. Adjustments E-156.7 and E-159.4, in Schedule 10, adjust the 2007 test year pension cost for the MPS and L&P divisions, respectively, to reflect a normalized level of contributions to the pension fund. Adjustments E-156.6 and E-159.3, in Schedule 10, adjust MPS's and L&P's 2007 test year pension cost to reflect the correct amortization amount for the Prepaid Pension Asset included in the stipulation and agreement in Case No. ER-2007-0004.

Staff Expert: Paul R. Harrison

J. SO_2 Emissions Allowance Inventory

Unlike many other Missouri electric utilities (including KCPL), GMO is in a position of needing to buy and hold in inventory more SO_2 emission allowances (SO_2 allowances) than it receives from the U.S. Environmental Protection Agency (EPA). Under the FERC uniform system of accounts (FERC USOA), the inventory of SO_2 emission allowances is recorded in FERC account 158.

The EPA withholds some of the allowances it issues each year to GMO and auctions them off to the highest bidder. GMO records the proceeds from the EPA auctions in FERC account 254, the FERC USOA regulatory liabilities account, as an offset to the value of the emissions allowances inventory in FERC account 158. For ratemaking, the FERC account 158 balance (net of the FERC account 254 balance) is included as an addition to rate base.

For MPS and L&P, Staff has included in its updated September 30, 2008 case the appropriate portion of the balance of account 158 (net of account 254) as an addition to the rate base of MPS and L&P. This approach is consistent with the treatment in the last GMO Rate Case No. ER-2007-0004.

Staff Expert: V. William Harris

VI. Income Statement - Revenues

A. Rate Revenues

1. Introduction

This section describes how the Staff determined the level of GMO Operating Revenues for both MPS and L&P. Since the largest component of operating revenues result from rates charged GMO's retail customers, a comparison of operating revenues with cost of service is fundamentally a test of the adequacy of the currently effective Missouri retail electricity rates. If the overall cost of providing service to Missouri retail customers exceeds operating revenues, an increase in the current rates GMO charges its Missouri retail customers for electricity may be appropriate. Because GMO has two different sets of rates in different parts of its service area (the areas formerly served by Aquila as Aquila Networks-MPS and Aquila Networks-L&P, which in this report are, for convenience, called MPS and L&P, respectively, the Staff determined operating revenues and cost of service for each of the two different parts of GMO's service area, *i.e.*, MPS and L&P.

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 GMO's charges for providing electric service to its Missouri retail customers. GMO's revenues for MPS and L&P 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

To determine the level of MPS and L&P rate revenues, the Staff has applied standard ratemaking adjustments to test year (historical) sales (kWh) and revenue data for both MPS and L&P service areas. The intent of these adjustments to test year Missouri rate revenues is to determine the level of revenue that the Company would have collected from the customers in each service area on an annual basis, under normal-weather or climatic conditions, based on information "known and measurable" by the end of the update period. In this particular case, the test year is calendar year 2007 and the update period ends September 30, 2008.

Rate revenue for both MPS and L&P has been developed and summarized in two different ways: one way is by type of regulatory adjustment; and a second way is total rate revenue by rate class. The Rate Revenue Summary Tab of the Staff Accounting Schedules summarizes rate revenue both ways, i.e., by type of adjustment and by rate class. The rate classes shown for the MPS service area are Residential (RES), Small General Service (SGS), Medium General Service (MGS), Large General Service (LGS), Large Power Service (LPS), Special, and Lighting. For the L&P service area classes shown are Residential (RES), Small General Service (SGS), Large General Service (LGS), Large Power Service (LPS), and Lighting.

Staff workpapers provide the source numbers and analysis for the individual rate codes, and present a much more detailed version of the summary table.

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

a. weather normalization
b. annualization for the rate change on May 31, 2007
c. 365-day adjustment
d. customer growth
e. large customer annualization
f. rate switching by large customers
g. 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. Other Revenue Accounts

Staff reviewed the amounts MPS and L&P have included in their cost of service calculation for Other Revenues; which include forfeited discount, miscellaneous service revenues, rent from electric property, and other electric revenues, among others. The analysis of these amounts included a review of the revenues over the last six years through December 31, 2007. 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, therefore do not require adjustment. Staff will examine these revenue accounts again during its true-up audit through March 31, 2009.

Staff Expert: Kofi Boateng

4. Removal of Inter-Company Off-System Sales Revenue

This adjustment eliminates inter-company off-system sales that were recorded during the test year between MPS and L&P. An inter-company transaction is a transaction between corporations that are members of the consolidated group. The source for the eliminated off-system sales for both MPS and L&P is the actual per book amounts for calendar year 2005, booked to Federal Energy Regulatory Commission (FERC) account 447031. A jurisdictional allocation factor was later applied to the inter-company revenue amount booked to MPS, consistent with its retail operations. This is adjustment Rev-11.1 for MPS and Rev-11.1 for L&P.

Additionally, Staff has made an adjustment to remove the off-system revenue associated with West Plains Energy Kansas Electric (WPKSE) that was booked to MPS operations during the test year. Since, the WPKSE properties were sold during the test year. This is adjustment Rev-12.1 for MPS.

Staff Expert: Kofi Boateng

5. Regulatory Adjustments to Test Year Sales and Rate Revenue

a. Weather Normalization

i. The Purpose of (Need 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, 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 "[a] 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

[12] National Oceanic and Atmospheric Administration

temperature for weather-normalizing electricity use. Staff needs *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 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.

[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.

Staff uses normal weather in both the normalization of class usage and hourly net system loads. This information was provided to Staff witness Walter Cecil for weather normalization.

Staff Expert: Manisha Lakhanpal

ii. Weather Normalization of kWh Sales

Analysis of GMO rate class kWh usage data was conducted using the Electric Power Research Institute's (EPRI's) Hourly Electric Load Model (HELM). The same analysis was conducted for both MPS and L&P. The following discussion applies to both analyses.

The consumption of electricity is sensitive to weather conditions. Air conditioning response increases as temperature increases and electric space heating response increases as temperature decreases. Consequently, the magnitude and shape of MPS's and L&P's electric load shapes are related to daily temperatures, usage of air conditioning and electric space heating.

Winter and summer temperatures during the 2007 test year varied sufficiently to result in both cooler-than-normal and warmer-than-normal months in each season; therefore, actual electric loads were adjusted upward and/or downward in those months to derive normal electric loads. Test year billing month adjustments for weather are found on Schedule WC-1 for MPS and Schedule WC-2 for L&P.

Staff weather normalized the test year electricity usage (kWh) of the following MPS classes: Residential General Service, Residential Space Heating, Small General Services, and Large General Services. Staff weather normalized the kWh of the following L&P classes: Residential General Service, Residential Space Heating, Small General Service, and Large General Service.

Neither Staff nor GMO weather normalized the test year electricity usage (kWh) of either the MPS or the L&P Large Power Services classes. 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 inconsistent with historical trends for a particular customer, 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 the Rate Revenue Section of this report.

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 it makes the class as a whole appear to be more weather sensitive than it is.

Finally, Staff excluded Large General Service, primary MPS customers from its MPS Large General Service weather normalization due to a dominant non-weather sensitive member in that class.

Staff Expert: Walter Cecil

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

The Staff used an average realization method to calculate any adjustment to rate revenue associated with the weather normalization of these kWh sales for the Missouri retail rate groups. The monthly weather normalization percentage adjustment was applied to actual kWh sales This method prices the kWh sales adjustment at the same average price as all other sales in that month for that specific rate group, based on the underlying assumption that the weather normalization 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 only affects those charges directly related to kWh sales.

Staff Expert: Curt Wells

b. Annualization for Rate Change

One important determinant of rate revenues in this case is the annualization of current rates (effective May 31, 2007). Test year (calendar year 2007) rate revenues reflect rates prior to May 31, 2007 and current rates after May 31, 2007 as established in Case No. ER-2007-0004. Thus, test year revenues for MPS and L&P are understated by the difference between the amount that was actually billed to customers (prior to current rates effective May 31, 2007) and the revenue that would have been realized by the Company if the current rates had been in effect throughout the entire test year. The Staff computed annualized revenues on May 31, 2007 rates for each class by applying May 31, 2007 rates to test year annualized billing units for each class. This adjustment affected all rate classes in MPS and in L&P.

Staff Experts: L&P Large Power Class – Michael S. Scheperle
All other classes - Curt Wells

c. 365-Days Adjustment

Rate revenues and kWh sales are measured by billing month (the period of time over which the staggered bill cycles result in each customer being billed precisely once) rather than by calendar month. A bill cycle is the approximately 30 day period between a customer's 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 billing month of July for that customer. The usage from July 18 to August 17 would be included in the billing month of August for that customer. But, only the usage from July 1 to July 31 is included in the calendar month of July. The test year is the twelve calendar months ending December 31, 2007. To the extent that a billing year contains more or less than 365 days worth of usage, an adjustment to kWh sales and rate revenues is made. The Staff calculated a days' adjustment to revenues for each rate class in the same manner as it computed weather-normalized revenues. Days' adjustments are also known as "unbilled" sales and "unbilled" revenues on financial statements.

Staff Experts: kWh sales -Walt Cecil; L&P Large Power Revenues – Michael S. Scheperle
All Other Classes Revenue: Curt Wells

d. Customer Growth

Customer growth adjustments were made to test year rate revenues to reflect the additional rate revenue that 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. KWh sales were then adjusted by the same percentage as revenue. For MPS, customer growth was calculated for the MO860 and MO870 Residential rate classes, MO710/711 Small General Service rate classes and the MO720 Large General Service rate class. For L&P, customer growth was calculated for the MO910/911 and MO920/921 Residential rate classes, and MO930 and MO931 Small General Service rate classes and the MO940 Large General Service rate class.

e. 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, the September 30, 2008 report indicates that MPS and L&P have experienced an increase in their revenues since the end of the test year, due to overall growth in the number of their 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. Thus, 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-2.7 for MPS and Rev-2.7 for L&P.

Staff Expert: Kofi Agyenim Boateng

f. Large Customer Annualization and Rate Switching

The general intent 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. It is customary for Staff to annualize each of the very largest customers to reflect 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 12 months of representative usage and revenue data for each large customer active at the end of the update period.

During this particular test year four customers in MPS and five customers in L&P were in their respective LPS rate class for less than the full year. These customers are known as "Rate Switchers" because they switched from one rate class to another. In addition, fourteen L&P customers and one MPS customer were switched within the LPS class to better differentiate them by voltage or by a specific rate rider, respectively. While the overall effect of rate switching on kWh sales nets to zero (one class' increase exactly equals the other class' decrease), the effect of the switching was to reduce overall rate revenues.

Those customers who switched <u>into</u> the LPS rate codes were handled as part of the Large Customer Annualization. No customers switched <u>out</u> of the LPS class during the test year and update period.

In addition to large Customer rate switching, a "Fixed-Bill" pilot program in the L&P area was ended during the update period. Sales and revenue from customers in this program's rate code were moved to the customers' original respective rate codes.

Staff Experts: MP S - Curt Wells, L&P – Michael S. Scheperle

g. Customer Discounts

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 GMO's service territory—the same EDR is available to MPS and L&P customers. 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 which contract year the customer is in, the discount can be as high as 30% (year 1) to as low as 10% (year 5). The 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 both MPS and L&P revenues because fostering economic development is assumed to be a benefit to all ratepayers.

Staff Experts: MPS - Curt Wells, L&P – Michael S. Scheperle

Curtailment Demand Rider: Curtailment Demand Rider payments in the form of credits are made to customers that agree to curtail a portion of their summer (June 1 through September 30) peak load when requested by GMO. However, no customer is required to reduce demand more than twenty (20) times in any contract year. Since these discounts benefit all ratepayers by reducing the need for additional production capacity, they are included in the determination of GMOC's revenues.

Staff Expert: Michael S. Scheperle

6. Results

Normalized and annualized kWh sales were used in the development of NSI. Rate revenue, for both the MPS and L&P service areas, with adjustments, are at the Rate Revenue Summary Tab of the Staff Accounting Schedules.

B. Bulk Power Sales

1. Off System Sales

Off-system sales are sales of electricity made at times when a utility has met all obligations to serve its native load customers and has excess energy to sell to others. The off-system sale transactions result in profits (net margin) to the selling entity, in this case, GMO.

It is appropriate to include the off-system sales in this case because Missouri retail electric customers are paying for all costs associated with the facilities needed to make these sales. Adjustment Rev-10.1 of Accounting Schedule 10 reflects the respective MPS and L&P levels of actual off-system sales for the 12-month period ending September 30, 2008. In addition, as an offset to the off-system sales, the fuel costs and purchased power costs relating to the off-system sales were also adjusted to reflect the actual results for MPS and L&P for the 12-month period ending September 30, 2008.

Staff Expert: V. William Harris

VII. Income Statement - Expenses

A. Fuel and Purchased Power Expense

The fuel and purchased power costs relating to off-system sales for MPS are reflected in Staff adjustments E-7.1, E-34.1, E-54.1 and E-83.1, on Accounting Schedule 10, Adjustments to Income Statement.

The fuel and purchased power costs relating to off-system sales for L&P are reflected in Staff adjustments E-7.1, E-36.2, E-58.1 and E-84.1, 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 determined independent of Staff's fuel model. 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 the Staff's fuel model are commonly referred to as capacity (or demand) charges and are annualized separately from purchased power energy costs. Adjustments for these costs for MPS and L&P are in Accounting Schedules 10.

a. Fuel Adders

As described above, fuel adders do not vary directly with the amount of electricity produced, so these costs are not included in the 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. Fuel adders include rail car expense, fly ash removal, freeze suppression, non-labor fuel handling costs and natural gas pipeline reservation charges.

The Staff used the actual cost MPS and L&P each incurred in calendar year 2007 (test year) as the annualized level for all fuel adders for them, respectively, in this direct filing.

Staff Expert: V. William Harris

b . 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 GMO. GMO 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 adjustments E-53.1 and E-54.1 annualize purchased power demand charges for MPS and L&P, respectively, 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. The Staff reviewed each of these contracts and determined the appropriate costs per megawatt hour and the amount of megawatts purchased. The Staff included the costs reflected in GMO's capacity agreements that were in effect on September 30, 2008.

Staff Expert: V. William Harris

2. Variable Costs

The Staff estimates the variable fuel and purchased power expense for GMO for the updated test year ending September 30, 2008 to be $209,838,935.

The Staff used the RealTime ® production cost model to perform an hour-by-hour chronological simulation of GMO's generation and power purchases (electric model), and an hour-by-hour chronological simulation of Lake Road Plant steam boiler steam generation (steam model). The Staff used both electric and steam models to determine annual variable cost of fuel and purchased power to economically match GMO's electric load within the operating constraints of it's resources used to match that load. These amounts are supplied to Auditing Staff who use this input in the annualization of fuel expense.

Both models operate in a chronological fashion, matching each hour's energy demand before moving to the next hour. The electric model schedules 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 electric model closely simulates the way a utility should dispatch its generating units and purchase power to match the net system load in a least cost manner. The steam model schedules boilers to dispatch in a least cost manner based upon fuel cost while taking into account boiler operation constraints. This steam model closely simulates the way a utility should dispatch its boilers to match steam sales load in a least cost manner.

Inputs provided by the Staff are: fuel prices, spot market purchased power prices and availability, hourly net system input (NSI), and unit/boiler planned and forced outages.

The Staff relied on GMO responses to data requests for factors relating to each generating unit such as: capacity of the unit, unit heat rate curve, capacity of the boilers, boiler efficiencies, primary and startup fuels, ramp-up rate, startup costs, fixed operating and maintenance expense. Information from GMO's firm purchased power contracts such as hourly energy available and prices are also inputs to the model.

Staff Expert – David W. Elliott

a. Fuel Prices

The Staff computed the fuel expenses for MPS and L&P using prices and quantities incurred by GMO through September 30, 2008. This included using fuel prices for coal, natural gas and oil, including transportation charges in fuel accounts 501 (coal), 547 (natural gas) and 555 (energy portion of purchased power expense).

Staff Expert: V. William Harris

b. Coal Prices

The Staff determined its coal price by generation facility based on a review and analysis of GMO's coal purchase (supply) and coal transportation (freight) contracts for MPS and L&P. The Staff's proposed coal prices for MPS and L&P reflect GMO'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 the Staff's fuel model were calculated using the actual delivered cost of natural gas for the 2007 test year.

Staff Expert: V. William Harris

d. Oil Prices

The Staff used the actual cost GMO paid for its most recent fuel oil purchases. GMO burns 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 GMO 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. The Staff believes GMO's most recent fuel oil purchase prices are the best available fuel oil cost to input into the fuel model for determining GMO's variable fuel and purchased power expense for MPS and L&P on a going forward basis.

Staff Expert: V. William Harris

3. Purchased Power – Energy (Spot Market) Prices

Staff adjustments E-50.1 and E-52.1 annualize purchased power energy charges for MPS and L&P, respectively, based on the Staff's fuel model results. These purchased power energy charges represent the energy GMO purchases on the spot market and through contracts to meet the system load requirements of its MPS and L&P retail electric customers. Staff expert David Elliott is responsible for determining the appropriate level of power purchased and the proper price for this power.

Staff Expert – V. William Harris

4. Removal of Inter-Company Off-System Sales and Fuel and Purchased Power

Consistent with the removal of inter-company off-system revenues from cost of service for both MPS and L&P, the Staff is making an adjustment to eliminate the inter-company off-system costs associated with fuel and purchased power that were recorded during the 2007 test year. These are adjustment E-8.1, E-35.1, E-56.1, and E-57.1 for MPS; and E-8.1, E-39.1, E-60.1, and E-61.1 for L&P.

Similarly, off-system costs associated with the West Plains Energy Kansas Electric properties that were sold during the test year were also removed from MPS' cost of service. These are represented in Staff's Accounting Schedule as adjustments E-9.1, E36.1, E-55.1, and E-58.1.

Staff Expert: Kofi Boateng

5. Allocation of Fuel and Purchased Power Costs

Staff has developed a methodology to allocate KCP&L Greater Missouri Operations Company's (GMO) net fuel and purchased power costs between its operations used to provide service in its MPS and L&P service areas. The purpose of this method is to fairly distribute these costs between MPS and L&P based on how much energy each needs to serve its native load customers. The output of the method yields hourly allocation percentage factors which represent the percentage of the total fuel and purchased power costs each incurs to meet native load.

When Great Plains Energy (GPE) acquired Aquila, Inc., now known as GMO, it agreed to keep the rate base for the then Aquila Networks-MPS and Aquila Networks-L&P operating divisions separate. The Commission approved GPE's acquisition of Aquila in Case No. EM-2007-00374. When Aquila (then known as UtiliCorp United, Inc. and now known as GMO) acquired St. Joseph Light and Power Company in 2000, it also agreed to keep the rate bases separate for the service areas of the two merging entities. Subsequently, Aquila created the Aquila Networks-MPS for its operations providing service in the pre-merger Aquila Missouri service area and Aquila Networks-L&P for its operations providing service in the former

St. Joseph Light and Power Company territory. The Commission approved the merger of UtiliCorp United, Inc. and St. Joseph Light and Power Company in Case No. EM-2000-292.

After a short review of the data, and in light of the no detriment standard that applies to mergers and acquisitions, the reasoning for keeping different rates in these service areas is clear. L&P has a small load that is usually served with inexpensive base load generation and energy obtained via a very economically advantageous capacity purchase agreement. MPS has three times the load of L&P and relies on more expensive base load generation, a not quite so economically advantageous capacity agreement, much more expensive gas generation and even more expensive purchased power from the energy market.

There are synergies from the combination MPS and L&P. In all most all instances an economic dispatch of the joined generation fleets and capacity purchases can result in cheaper operating expenses for the participating entities. This means that MPS and L&P can obtain power transfers from each other for less money than buying energy on the power market. In general there are four scenarios that can occur:

1. Both entities are meeting native load and had no excess generation.
2. One entity is meeting native load and has excess generation that is transferred to the other entity at a price below the market price.
3. One entity is meeting native load and has excess generation but the other entity can obtain power from the market at a lower price.
4. Neither entity is meeting native load and both must obtain power from the market.

Appendix 4 shows graphical representations of these scenarios.

Staff's allocation methodology uses hourly normalized loads (net system input) for each operating entity and the hourly output of the fuel model (based on those hourly loads) along with normalized purchased power prices. It calculates the percentage of the total cost for which each operating entity is responsible to meet its native load. Staff's normalized fuel expense estimate is actually the average of ten fuel model runs, i.e., ten iterations. Therefore, to estimate the normalized allocation of costs between the two entities, the allocation methodology must be conducted for each of the ten fuel run iterations and then also averaged.

The hourly energy cost and the available amount of energy from each source[14] to meet load were obtained from the output of an iteration of the fuel model. Specifically the allocation method inputs include the following hourly data from the fuel run iteration for the test year ending December 31, 2007.

- Generation (Megawatt (MW) and $/MW for each generator)
- Capacity contract transactions (MW and $/MW for each capacity transaction)
- Spot purchased power transactions (MW and $/MW)
- Total net system input for the GMO system
- Individual net system input for MPS and L&P

The allocation methodology is based on the idea that each operating entity is first and foremost obligated to use its least expensive resources available to serve its load and then to obtain the least expensive source for additional power, when needed.

The allocation method makes several passes through the hourly data to determine the percentage of fuel costs incurred by each operating entity. The first thing that the allocation method does is, using the fuel model iteration output, separate the energy supplied by each operating entity and assign ranks to each energy source from least expensive to most expensive for the separate entities. The next step is to look at each hour and assign the cheapest generation available for that operating entity to serve its native load and track the cost and amount of the energy from that generator. This is a bookkeeping type pass through the data which also keeps track of whether or not native load is met by the generation sources of each entity, how much

[14] An energy source could be a turbine-generator, a capacity purchase, a purchased power transaction, or an energy transfer from the other operating entity

extra energy is available from each entity (if any), and the cost of the excess energy. When all of the entries for that hour have been processed, the allocation method determines which of the four scenarios described above it has encountered. This information is saved to be used during the next pass through the data which is slightly more complicated.

When the native load has been met, the allocation method stores the MW and costs and moves on to the next hour. If excess energy was generated, again the allocation method stores that information and moves on to the next hour. If energy is needed to meet the load requirement of an entity, a decision is made on how to economically meet this need, i.e., where to obtain the least expensive energy. This involves either taking a transfer from the other operating entity or taking purchased power from the energy market. Neither operating entity would ever take cheaper power away from the other operating entity if it was needed it serve its own load. However, there might be the case where it is cheaper for one operating entity to purchase power in the power market than it is to take a transfer from the other operating entity. This scenario does not occur often because typically a generation source will not be dispatched unless it can be operated at a price lower than the market price of available energy.

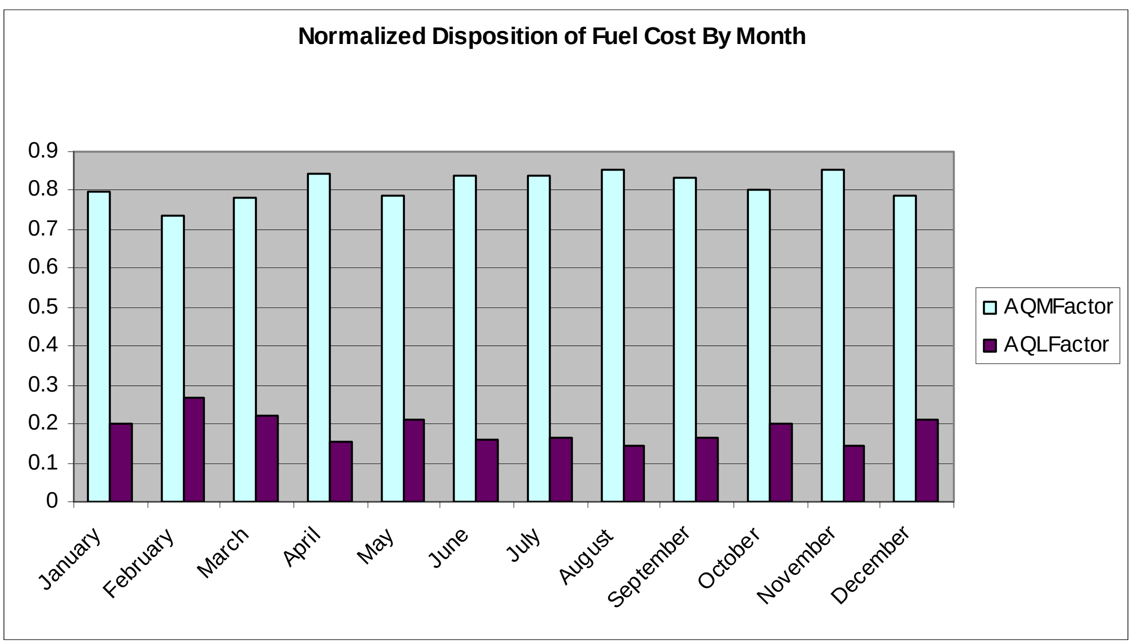
Because the fuel model is designed to meet the total net system load of both operating entities, the energy generated by each operating entity plus the purchased power transactions equals the required total net system load. In actual operation many transactions occur with off-system sales thrown into the mix. This allocation method could be extended to allocation of off-system sales but in this case, off-system sales were handled separately from the fuel model.

For each iteration of the fuel model, hourly outputs include the generation and costs for each generator, and each purchased power transaction needed to meet native load. Total net fuel costs are calculated with this information. The allocation method yields hourly allocation factors which can then be used to calculate the hourly portions of the total net fuel costs for which each operating entity is responsible. The following table and chart summarizes the allocation factors determined by the allocation method for one of the fuel model iterations.

Table I: Monthly Fuel Allocation Factors

Month	***MPS***	***L&P***
January	0.7977	0.2023
February	0.7346	0.2654
March	0.7799	0.2201
April	0.8445	0.1555
May	0.7893	0.2107
June	0.8393	0.1607
July	0.8365	0.1635
August	0.8537	0.1463
September	0.8330	0.1670
October	0.8006	0.1994
November	0.8552	0.1448
December	0.7892	0.2108
Annual Average:	**0.8128**	**0.1872**
Max	**0.8552**	**0.2654**
Min	**0.7346**	**0.1448**

Chart I: Monthly Fuel Allocation Factors



The allocation method outputs for this fuel model iteration are close to the percentages used in the last rate case to allocate fuel costs between entities (0.81 for MPS and 0.19 for L&P). Because of the time that it takes to calculate the allocation factors from the final fuel run, 0.81 and 0.19 were also used for Staff's Cost of Service filing in this case. Although the annual averages are close to what was used, closer inspection of the data reveals a large range in values over the year with MPS's monthly allocations ranging from 0.73 to 0.85 and conversely L&P's monthly allocations ranging from 0.14 to 0.27. The results for the summer months were the most varied.

Staff proposes this topic be discussed with GMO and other interested parties in this case in greater detail so that this allocation method could be used to calculate these allocation factors on a summer and non-summer basis to be used to determine base fuel costs for the fuel adjustment clause. Staff is in the process of running the allocation method for all ten fuel model iterations produced by Staff and the results, along with the spreadsheets used to calculate the results, will be provided to the parties as soon as possible.

Staff Expert: Erin L. Maloney

6. 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.

The 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. The 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

7. Capacity Contract Prices and Energy

Capacity contracts are contracts for a specific amount of capacity (megawatts) and a maximum amount of hourly energy (megawatthours). Prices for the energy from these capacity contracts are based on either a fixed contract price or the generating costs of providing the energy. Capacity contracts include: Gray County Wind Contract, NPPD Cooper Contract, NPPD Gentleman Contract, and a generic contract.

GMO's actual hourly contract transaction prices in the period of twelve months ending September 30, 2008, obtained from the data GMO supplied to comply with 4 CSR 240-3.190 were used to calculate the average monthly prices.

Staff Expert: David W. Elliott

8. 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 numbers 182 and 183 for the two areas where GMO has different rates (MPS and L&P), respectively. Hourly load data submitted monthly by GMO 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 GMO's electric service territory, the magnitude and shape of GMO's net system input is directly related to daily temperatures. The net-system's reaction to temperature in MPS differed from the net-system's reaction to temperature in L&P. Therefore, each was analyzed separately.

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 were 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 normalized, annualized test year usage for each of GMO's retail customer classes was completed, any weather-normalized wholesale usage was added to the appropriate division. Then the annual usage was increased by the average annual loss factors. This produces an annual sum of the hourly net system loads that equals the adjusted test year usage, plus losses, and is consistent with Staff's normalized revenues for each division.

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

[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.

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 were 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 GMO's system between GMO'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 GMO'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 system energy loss percentage for the twelve months ending December 2007 of 6.09% of NSI for GMO-MPS and 6.07% of NSI for GMO-L&P. These line loss percentages are being utilized by Shawn Lange in developing the loads used in Staff's fuel model.

Staff Expert: Alan J. Bax

9. Planned and Forced Outages

Planned and forced outages are infrequent in occurrence, and variable in duration. In order to capture this variability, the MPS and L&P generating unit outages were normalized by averaging the nine years of actual values taken from data supplied by GMO. Also the outages for the Lake Road boilers located in L&P service area in St Joseph, Missouri, were normalized by averaging the seven years of actual values taken from data supplied by GMO.

Staff Expert: David W. Elliott

10. Capacity Requirements for the Territory Formerly Known as MPS

In September 2003, Staff testified in Case No. EF-2003-0456 to its concerns regarding Aquila's lack of planning to replace the 500 megaWatts ("MW") of summer power it was then obtaining from the exempt wholesale generator ("EWG") Aries plant owned jointly by Aquila's subsidiary Aquila Merchant Services, Inc. ("Aquila Merchant") and Calpine through a five-year purchased power agreement ("PPA") that was to end in May 2005 ("Aries PPA"). At that time, Aquila had not informed Staff of how it planned to meet the capacity needs of MPS for the summer of 2005.

On January 27, 2004, Aquila met with Staff to explain its planned power supply acquisition process for the next five years. In this meeting, Aquila told Staff that its preferred/proposed resource plan for MPS over the short term was to build three 105 MW combustion turbine generators (“CTs”) and to enter into three-to-five year PPAs based off of the bids to its 2003 request for proposals (“RFP”).

Staff was concerned about the short-term nature of Aquila’s preferred/proposed plan for MPS, so three days later, on January 30, 2004, the Staff responded with a letter to Mr. Dennis Williams of Aquila, expressing its concern about Aquila’s short-sightedness in its resource planning. The letter also explained it was the Staff’s belief that Aquila needed to be looking at baseload generation and the Staff’s was concerned that Aquila not become overly dependent on short-term PPAs.

Aquila met with the Staff only ten (10) days later, on February 9, 2004, for Aquila’s semi-annual resource plan update. This update, which took into consideration events over a twenty-year time horizon, showed in part that according to Aquila’s analysis, Aquila’s least-cost plan for MPS was to build five 105 MW CTs in 2005 and to purchase a small amount of capacity on the market in 2005. Aquila’s preferred plan was different from its long-range least cost plan only in that instead of building five 105 MW CTs in 2005, Aquila would build three 105 MW CTs in 2005, enter into a 200 MW PPA in 2005, and purchase a small amount of capacity on the market.

Aquila followed its preferred plan for MPS and built three 105 MW CTs at its South Harper site near the City of Peculiar (“South Harper power plant”) and executed short-term PPAs with its affiliate Aquila Merchant for power from Aquila Merchant’s Crossroads plant in Mississippi (“Crossroads power plant”) to meet Aquila’s capacity needs for 2005.

In Aquila’s first general electric rate increase case in Missouri after the Aries PPA expired, Case No. ER-2005-0436, the Staff asserted that, given the information available from the resource planning process at the time Aquila decided how it would replace the power it was obtaining through the Aries PPA, Aquila should have built five 105 MW CTs in time to meet the capacity need resulting from the expiration of the Aries PPA in May 2005. In this case, Staff stated that it believed then, as it does now, that Missouri electric utilities should carefully engage in risk and contingency analyses of their resource plans and chose a resource plan that is robust across many scenarios involving many probable future events. Prudently building and owning generation, whether baseload, intermediate or peaking, provides price stability for consumers. PPAs are useful tools, but short-term PPAs should not be relied upon as long-term solutions to capacity needs in the planning process, without a firm long-term contract in hand. It was, and still is, the Staff's position that, instead of relying on short-term PPAs, Aquila should have built and had available by the summer of 2005 five 105 MW CTs, which would then have provided Aquila with 525 MW of capacity that would be available to Aquila to serve its customers for the following thirty years of their design life, until 2035.

While Aquila had built and had equitable ownership of its South Harper power plant before the "fully operational and used for service" cut-off date in Case No. ER-2005-0436, the legality of the plant was in question due to litigation with Cass County, Missouri, which had obtained a court order enjoining construction of the plant. Therefore, in lieu of the costs of South Harper power plant, which had three 105 MW CTs installed, and Aquila's PPAs, the Staff included the cost of a new six 105 MW CT site with five installed 105 MW CTs in its case to approximate a self-build option for MPS. The parties in Case No. ER-2005-0436 entered into a Stipulation and Agreement regarding fuel and purchased power expenses, but the Stipulation and Agreement was silent regarding how Aquila should meet its capacity requirements.

In Aquila's next rate increase Case No. ER-2007-0004, Aquila was still relying on the three 105 MW CTs at its South Harper power plant and short-term PPAs to meet MPS's summer load. However, because the legality of the plant was still in question due to litigation with Cass County, Missouri, consistent with its position in the preceding Aquila rate increase case, Staff took the position that Aquila should have built five 105 MW CTs in 2005 to meet MPS's summer capacity and energy needs. As in the prior case, Staff, Aquila and other parties entered into another Stipulation and Agreement regarding fuel and purchased power expenses that was silent on how Aquila should meet its capacity requirements.

Now, the litigation regarding the South Harper power plant has settled, a new law regarding certificates of convenience and necessity ("CCNs") has been enacted by the Missouri Legislature, and the Commission has before it in Case No. EA-2009-0118, a Stipulation and Agreement for a CCN for the South Harper power plant, as well as an associated substation. Until, and unless the Commission issues a CCN for the South Harper power plant, the legality of the plant is unresolved and in that circumstance Staff will not include the cost of that plant in rate base; therefore, Staff's position remains that Aquila should have built five 105 MW CTs early enough to meet the capacity needs of MPS in 2005.

In addition, MPS customers' need for electricity has grown from 2005 to 2008. With the five CTs in its resource mix, MPS only needs an additional 100 MW of capacity. Instead of including the Crossroads power plant, in this case Staff is imputing a 100 MW short-term PPA for MPS. A utility should locate and size a generating plant to serve its native load. The Crossroads power plant was not located or sized to meet MPS's native load. It was built as a merchant plant to sell energy at market value. Under the right circumstances, such as distress sales, acquisition of plants built by others, including those built as merchant plants such as Crossroads, could be a preferred option. Staff did not include the Crossroads power plant for two reasons: (1) affiliate transaction concerns discussed in greater detail in the next section of this report; and (2) the cost of transmission to move the Crossroads energy to GMO's territory.

Even though it is Staff's position that the best resource for an electric utility is "steel-in-the-ground," i.e., utility constructed and owned generation, Staff recognizes that short-term PPAs are appropriate in circumstances where the electric utility is adding capacity in the near future. In this case, Staff is including a "hypothetical" short-term contract to bridge the need between the five CTs and GMO's next generation capacity addition for MPS.

Therefore, the capital costs of five 105 MW CTs on a six 105 MW CT site are included in Staff's case for MPS, and the capacity costs of a generic 100 MW PPA are included in expenses for MPS. Instead of the three 105 MW CTs at the South Harper power plant and GMO's existing PPAs, Staff included five 105 MW CTs on a six 105 MW CT site and a generic 100 MW PPA in its fuel run to determine fuel and purchased power expense.

Staff is still concerned with GMO's resource plans. While GMO is adding capacity from Iatan 2 to its resources in 2010, ** . **

Even if the Commission includes the 300 MW Crossroads power plant in MPS's ratebase, given the load forecast for MPS from GMO's resource planning compliance filing (Case No. EO-2007-0298), ** . ** If MPS load grows as forecasted and GMO does not add more capacity, GMO will have depended on short-term PPAs to meet its capacity needs for ** ______________________________ . ** Prudently building and owning generation, whether it is baseload, intermediate or peaking, provides price stability for consumers. This is why Staff's case assumes GMO built five 105 MW CTs in 2005 to serve MPS.

Staff Expert: Lena M. Mantle

a. MPS Prudent Combustion Turbine Site

The Staff is sponsoring adjustments to MPS' 2007 books and records to continue the Staff's position in Aquila's last two rate cases, No. ER-2005-0436 and ER-2007-0004, as it relates to the MPS capacity issue described above. The Staff adjustments to MPS' cost of service in this case reflect the continuation of the Staff's position that Aquila should have addressed its capacity needs for MPS by building and owning five 105 MW CTs, and not continually rely on short-term purchased power capacity contracts.

The Staff determined and maintained in Aquila's last two MPS rate cases, Case No. ER-2005-0436 and No. ER-2007-0004, there was a need to remedy Aquila's failure to protect MPS' ratepayers from imprudent decisions on the part of Aquila's management as it related to the acquisition of capacity. The Staff is continuing that position with regard to MPS in this case.

In its direct filing in this case MPS has included in rate base 308 MW of capacity from Crossroads Energy Center (Crossroads) located in Mississippi. The following description of Crossroads is included in an October 31, 2008 Memo to Files from GMO witness Ron Klote, Senior Manager Regulatory Accounting:

Crossroads, physically located in Clarksdale, Mississippi, is a 308 MW combustion turbine power plant consisting of four General Electric 7EA units. It was built in 2002 by a non-regulated subsidiary of Aquila, Inc. titled Aquila Merchant Services. On March 31, 2007, Crossroads Energy Center was recorded at Net Book Value to a nonregulated business unit

CECAQ (Crossroads Energy Center Aquila) where it resided at the time of the acquisition of Aquila, Inc. by Great Plains Energy (GPE). On August 31, 2008 the Crossroads Energy Center was moved from GMO's business unit NREG, where it was recorded after the acquisition of Aquila, Inc. by Great Plains Energy on July 14, 2008, to MOPUB's books and records. MOPUB is the regulated business unit which previously served the territory known as Missouri Public Service. On September 5, 2008 GMO regulated jurisdictions filed a rate case including the Crossroads Energy Center in MPS's rate base at net book value.

The Staff made an adjustment to remove all plant and expenses related to Crossroads from its MPS revenue requirement recommendation to the Commission in this case. As described above by Staff witness Lena Mantle, the reason for the Staff's adjustment is to remedy Aquila's failure to replace the capacity it was obtaining from the Aires PPA, which expired on May 31, 2005, in a manner that would result in the lowest long-term revenue requirement for MPS ratepayers. Aquila should have constructed and owned five 105 MW CTs available by the summer of 2005 at a site without issues over Aquila's legal right to do so. Instead Aquila built three 105 MW CTs at its South Harper power plant site when Cass County had a court judgment enjoining construction of the power plant.

MPS' <u>South Harper</u> power plant is a natural gas-fired peaking facility capable of generating up to 315 MW located in Cass County, Missouri. As a peaking facility, the South Harper power plant typically operates during peak electricity demand periods, such as the hot summer days in June, July, August, and September; however, it may also operate in non-peak periods to support the power system grid during maintenance on other units, or during generation shortages and emergencies, or other circumstances where it is the lowest cost plant to dispatch. Major construction of the South Harper power plant was completed in June and July 2005.

As it did in Case No. ER-2005-0436, the Staff's revenue requirement calculation for MPS in this case reflects, as a proxy, the prudent costs incurred to construct the South Harper power plant (a six 105 MW CT site with three 105 MW CTs installed) plus a reasonable estimate of the costs MPS would have incurred to construct two additional 105 MW Siemens gas turbines at the time it built the three 105 MW CTs at the South Harper. The cost Staff included in this case represents a proxy for the six 105 MW CT site upon which Aquila should have built five 105 MW CTs for use by the summer 2005 ("MPS Prudent CT Site").

In addition to the capital and operating costs of the MPS Prudent CT Site, because of increased capacity needs since 2005, the Staff has included in its revenue requirement calculation for MPS in this case a reasonable estimate of the costs MPS would incur to purchase 100 MW of capacity. The Staff based this estimate on the costs of a recent MPS PPA.

To estimate the costs MPS would be incurring now for the Prudent CT Site, the Staff has taken MPS' 2007 test year costs of the three existing CTs at the South Harper plant site and factored them up on a pro rata basis. These adjustments are for costs of property taxes (Pilot payments, adjustment E181.4), maintenance (adjustment E20.2) and natural gas pipeline reservation charges (adjustment E32.2).

In addition, by inclusion in rate base, the plant costs for the Prudent CT Site will generate depreciation expense and an overall rate of return on the net rate base amount. The Staff has also calculated pro rata amount of depreciation reserve and deferred income taxes for the addition of MPS Prudent CTs 4 and 5 and reflected this amount in MPS' rate base.

In August 2008, GPE's management decided to include Crossroads in MPS' ratebase. This was an affiliate transaction from the unregulated Aquila Merchant subsidiary to MPS, but neither Aquila nor GPE has never obtained a variance from the Commission's Affiliate

Transactions Rule, 4 CSR 240.015, for this transaction, not even in Case No. EM-2007-0374, where the Commission only authorized KCPL and Aquila to engage in affiliate transactions between themselves.

Staff Expert: Charles R. Hyneman

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

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-2007-0374, remaining employees of the former MPS and L&P 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 Greater Missouri Operations: 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 entities, MPS and L&P. Since L&P operations supplies utility services to electric and steam customers, L&P labor costs must be further allocated between the electric and steam operations. This is accomplished through jurisdictional allocations in Staff's accounting schedules. 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 acquisition (July 14, 2008) through November, 2008. The actual charges made to the post acquisition 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. 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 Nuclear Operating Corporation, 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.

As of September 30, 2008, GMO'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 acquisition 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 GMO L&P.

On December 16, 2008, GPE was restructured with all GPE and GPES employees moving to the KCPL organization becoming KCPL employees. Since this occurred outside the update period used in this case of September 30, 2008, Staff has not 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 the Company.

Overtime payroll for MPS and L&P was calculated based upon a three-year average of overtime costs unique to each of the two divisions. The amounts are specific to 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 MPS and L&P.

As the result of KCPL’s operating agreements on 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, MPS and L&P 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 Empire District Electric Company, the other partner in Iatan, and to Energy Company, the 50% partner in the two LaCygne generating facilities. Jeffrey Energy Center billed payroll was included at the test year level adjusted for a wage increase and included in MPS annualized payroll.

The total annualized GPE and KCPL payroll costs allocated to MPS and L&P service territories also must 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 MPS and L&P 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 seventy (70) adjustments for both MPS and L&P by FERC account to reflect the adjustments 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 annualized payroll for GMO MPS as of September 30, 2008: E4.1, 10.1, 11.1, 12.1, 17.1, 18.1, 19.1, 20.1, 21.1, 30.1, 38.1, 39.1, 43.1, 44.1, 45.1, 46.1, 62.1, 63.1, 69.1, 71.1, 72.1, 74.1, 75.1, 76.1, 77.1, 78.1, 79.1, 84.1, 88.1, 91.1, 92.1, 94.1, 99.1, 100.1, 101.1, 102.1, 103.1, 104.1, 105.1, 106.1, 107.1, 108.1, 109.1, 113.1, 115.1, 116.1, 117.1, 118.1, 119.1, 120.1, 121.1, 125.1, 126.1, 127.1, 128.1, 129.1, 130.1, 131.1, 133.1, 136.1, 139.1, 142.1, 143.1, 149.1, 161.1, 164.1.

The following adjustments to the income statement reflect annualized payroll for GMO L&P as of September 30, 2008: E-4.1, 11.1, 16.1, 17.1, 22.1, 23.1, 24.1, 25.1, 26.1, 35.1, 40.1, 41.1, 46.1, 47.1, 48.1, 63.1, 64.1, 69.1, 71.1, 72.1, 73.1, 75.1, 76.1, 77.1, 78.1, 79.1, 80.1, 85.1, 89.1, 90.1, 92.1, 93.1, 95.1, 100.1, 101.1, 102.1, 103.1, 104.1, 105.1, 107.1, 108.1, 109.1, 110.1, 111.1, 115.1, 116.1, 117.1, 118.1, 119.1, 120.1, 121.1, 122.1, 124.1, 128.1, 129.1, 130.1, 131.1, 132.1, 133.1, 134.1, 136.1, 139.1, 142.1, 145.1, 146.1, 152.1, 166.1, 169.1.

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 and interns, an aggregate tax rate was applied based on the annualized payroll taxes for base payroll. The payroll taxes follow the same allocation process used to allocate base payroll.

Adjustment E-181.2 to the Income Statement reflects the annualized payroll taxes for GMO MPS.

Adjustment E-187.2 to the Income Statement reflects the annualized payroll taxes for GMO L&P.

Staff Expert: Keith A. Majors

3. Payroll Related Benefits

Staff annualized 401k expense based upon the test year percentage KCP&L match to eligible earnings applied to the MPS and L&P share of total annualized payroll, reduced for the payroll expense factor to capital. Staff used the test year KCP&L match to earnings as all employees are now KCP&L employees and the aggregate Company match to earnings is the most appropriate for the cost of service.

Medical costs were annualized based upon a calculation of twelve months ending September 30, 2008 of the MPS and L&P self funded cost, net of the test year ratio of employee contributions and including a small portion of premium based coverage.

By the true-up date of this case, all former Aquila employees will receive medical coverage through the Voluntary Employee Benefit Association (VEBA). Staff will examine the change in these costs and adjust them to an annualized level at the true-up.

Adjustments E-156.3 and 156.12 to the Income Statement reflect annualized employee benefits for GMO MPS.

Adjustments E-159.2 and 159.11 to the Income Statement reflect annualized employee benefits for GMO L&P.

Staff Expert: Keith 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

Financial Accounting Standard (FAS) 87 is the accrual accounting method for calculating pension cost for financial reporting purposes. However, for Kansas City Power & Light Greater Missouri Operation's or the former Aquila Networks Missouri Public Service and St. Joseph Light and Power regulated entities, MPS and L&P, both the Staff and the Company recommend continuation of the settlement agreement originally reached in Case No. ER-2004-0034 and continued in Case No. ER-2005-0436 and Case No. ER-2007-0004. The settlement agreement provides for the use of the minimum contributions required under the Employee Retirement Income Security Act (ERISA) for determining MPS's and L&P's pension cost for ratemaking purposes. ERISA was established by federal statute in 1976 and is intended to ensure the funding of defined benefit pension plans in the United States..

FAS 87 is an accrual accounting method required by the accounting profession under Generally Accepted Accounting Procedures (GAAP) for financial reporting purposes. Under FAS 87 a company accrues (expenses) an employee's earned pension benefits over the service life of the employee. The total obligation to the employee for pension benefits is accumulated annually until retirement in the Accumulated Benefit Obligation (ABO). Both financial statement expense recognition under FAS 87 and the funding requirements under ERISA are based upon the same pension plan obligation to employees enrolled in the plan. While different assumptions are used for the timing of pension cost recognition during the service life of the employee under FAS 87 and ERISA, both FAS 87 and ERISA are intended to address the same total ABO by the employee's retirement date. The Staff has historically used both FAS 87 and the ERISA minimum contributions for determining pension cost for ratemaking purposes.

In MPS's and L&P's last general electric rate case, Case No. ER-2007-0004, the parties entered into a settlement agreement to use the provisions that were established in MPS's and L&P's previous rate case, Case No. ER-2005-0436, which included the following provisions:

1) A Prepaid Pension Asset representing negative pension cost flowed through in rates in prior cases was agreed to in the stipulation and agreement in Case No. ER-2004-0034. This Prepaid Pension Asset is being amortized to cost of service over 5 1/2 years for the MPS division and 9.25 years for the L&P division starting

with the effective date of rates established in Case No. ER-2004-0034, April 22, 2004. The unamortized balance is included in rate base for the MPS and L&P divisions. This treatment was continued in the stipulation and agreement in Case No. ER-2005-0436 and ER-2007-0004.

2) Annual pension cost reflected in cost of service is to be based upon MPS and L&P’s ERISA minimum contributions requirements.

3) A tracking mechanism tracks the difference between the pension cost included in rates and MPS and L&P’s actual pension fund contributions during the period that existing rates are in effect. The resulting regulatory asset (actual fund contributions exceed rate recovery) and/or regulatory liability (actual fund contributions are less than rate recovery) are included in rate base and amortized to cost of service over 5 years.

The rate base amounts and cost of service adjustments the Staff has reflected in this current case, Case No. ER-2009-0090, are based on continuation of the agreements reached in the stipulation and agreements in Case Nos. ER-2004-0034, ER-2005-0436 and ER-2007-0004.

The Staffs rate base includes a Missouri jurisdictional balance of $2,233,545 and $16,121,101 for the MPS and L&P divisions prepaid pension asset unrecovered balance, respectively, as of September 30, 2008. This amount will be updated through March 31, 2009, in the true-up audit for this case. As of September 30, 2008, MPS and L&P divisions have collected $4,344,194 and $8,748, respectively, more in rates than the actual contributions made to the pension fund. This regulatory liability is reflected as a reduction to MPS's and L&P’s rate base and amortized as a reduction to pension cost over 5 years. Adjustments E-156.7 and E-159.4, in Schedule 10, adjust the 2007 test year pension cost for the MPS and L&P divisions, respectively, to reflect a normalized level of contributions to the pension fund. Adjustments E-156.6 and E-159.3, in Schedule 10, adjust MPS's and L&P’s 2007 test year pension cost to reflect the correct amortization amount for the Prepaid Pension Asset included in the stipulation and agreement in Case No. ER-2007-0004.

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 OPEBs expenses based on Financial Accounting Standard No. 106, *Employers ' Accounting for Postretirement Benefits Other than Pensions* (FAS 106) and Staff has provided sufficient costs in its revenue requirement calculation to reflect a proper level for these post-employment benefit costs for MPS and L&P. 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 limits restricts disbursements only for qualified retiree benefits" for the FAS 106 costs recognized in a utility's financial statements and that all the funds be used for employee or retiree benefits.

The MPS and L&P divisions are funding their annual FAS 106 costs. Staff adjustments E-156.8 and E-159.5 adjust the MPS and L&P test year 2007 FAS 106 OPEBs costs to reflect the more current FAS 106 calculation as of September 2008.

The Staff's adjustment annualizes OPEBs expense as calculated under FAS 106, for MPS and L&P employees. OPEB expense reflects MPS's and L&P's current liability to provide retiree medical payments to its current employees as well as to its retired employees.

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 106. FAS 158 require recognition of the overfunded or underfunded status of pension and other postretirement benefit plan 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, 2008, the measurement date is required to be the employers' fiscal year end. Staff adjustments E-156.8 and E-159.5 adjust MPS & L&P test year 2007 FAS 106 costs for the shift from fiscal year end to calendar year end.

Additionally, through meetings with the Company, the Staff discovered that the Company made a determination to combine all of its pensions and OPEBs into one plan. Through these meeting and data request responses from the Company, it is the Staff's understanding that KCPL, MPS and L&P expect significant increases in their pension and OPEBs costs on or about the time of the true-up of this rate case. The Staff has submitted data requests to obtain additional information and has requested copies of the Company's combined actuary reports as soon as they are available. These issues will be addressed in the true-up phase of this rate case.

Staff Expert: Paul R. Harrison

7. Supplemental Executive Retirement Plan (SERP) Expense

Included in the Staff's revenue requirement recommendation is the test-year amount of recurring SERP payments made by the Company to its former executive employees. A SERP is an additional executive pension compensation program which provides benefits to highly-compensated employees over and above the benefits provided under the regular pension plan.

In the test year MPS made $39,751 in SERP payments. In Adjustment E-156 the Staff removed the test year per book amount of SERP expense and included MPS' 2007 actual SERP payments.

The Staff has not included in the Company's revenue requirement any SERP payments for L&P. When Aquila purchased L&P in 2000, it also purchased the assets in L&P's funded SERP. It has been the Staff's position in prior rate cases and continues to be in this case that these assets are sufficient to pay for a reasonable level of SERP expense over the lifetime of the former St. Joseph Light and Power (SJLP) executives. Therefore, since Aquila purchased the assets in the SERP fund when it purchased L&P, there is no longer any SERP expense for the former SJLP executives.

Because of SERP's unique nature and the fact that the benefit represents an additional executive pension benefit over and above what is already provided in the regular pension plan, the Staff treats SERP costs somewhat differently from normal employee pension costs. The Staff's policy has been and continues to be the recommendation that SERP costs be included in the Company's cost of service if such costs are not significant, are reasonably provided for, and are able to be quantified under the known and measurable standard. MPS' annual recurring SERP payments of $39,751 meets this test.

Staff Expert: Charles R. Hyneman

8. Short Term Annual Incentive Compensation

The Aquila Variable Compensation was designed to grant cash awards based upon metrics in corporate, state, and individual employee measures. Within these measures are various metrics determined by management with various weights. The level of achievement of these goals, from threshold to maximum, determines the amount of weighting of that goal. Target award amounts are based upon classification of employee by band and status, field or support.

Staff has examined goals and metrics of this program in prior cases and has found them to be prudent with the exception of metrics based upon financial measures.

The former Aquila entities also employed a profit sharing program which awarded additional funds to employee 401k contributions.

However, upon the acquisition of Aquila, these programs were discontinued and will not pay any awards after the 2007 plan year. All obligations to former Aquila employees were satisfied prior to the merger. The Company did not attempt to normalize these costs. Therefore, Staff is removing the test year short term incentive compensation charged to MPS and L&P.

All KCP&L employees, including all former Aquila employees now employed by KCP&L, are covered under KCP&L's three short term incentive compensation programs. In Case No. ER-2009-0089, Staff removed the cost of the test year short term incentive compensation from the cost of service. Because of this removal, there is no allocation of short term incentive compensation from KCP&L to MPS or L&P similar to the allocation of payroll costs.

Adjustments E-156.5 and 156.9 to the Income Statement reflect the adjustments to remove short term incentive compensation from the cost of service for GMO MPS.

Adjustments E-159.7 and 159.8 to the Income Statement reflect the adjustments to remove short term incentive compensation from the cost of service for GMO L&P.

Staff Expert: Keith A. Majors

9. Long Term Incentive Compensation

During the test year, restricted stock was granted to senior executives of Aquila. Restricted stock is stock which must be held for a specific period of time before is can be transferred or sold.

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

1) Equity compensation was awarded based upon goals which are entirely or primarily tied to earnings, beneficial to shareholders, not customers.
2) Unlike other forms of employee compensation, equity compensation does not require a cash outlay by GMO MPS and L&P.
3) The program that granted these stock awards is no longer active and no additional grants will occur. All obligations to former Aquila employees under this plan have been satisfied.

Adjustment E-156.10 to the Income Statement reflects the adjustment to remove restricted stock expense from the cost of service of GMO MPS.

Adjustment E-159.9 to the Income Statement reflects the adjustment to remove restricted stock expense from the cost of service of GMO L&P.

Staff Expert: Keith A. Majors

10. MPS Share of Jeffrey Energy Center Miscellaneous Adjustments

The Company examined the test year transactions relating to Jeffrey Energy Center, adjusting for out of period costs and a different A&G loading rate. Staff reviewed these adjustments and found them to be correct.

Adjustments E-11.2, 12.2, 150.3, 154.2, 155.3, 156.11, and 181.3 to the Income Statement reflect the adjustments to normalize MPS share of Jeffrey Energy Center expenses for GMO MPS.

Staff Expert: Keith A. Majors

11. SJLP Share of Iatan Miscellaneous Adjustments

Similar to the MPS Jeffrey Energy Center adjustment, the Company examined the test year Iatan billings to L&P to remove any abnormalities and out of period costs. Staff reviewed these adjustments and found them to be correct.

Adjustments E-11.2, 16.2, 17.2, 64.3, 85.2, 153.3, 156.1, and 166.4 to the Income Statement reflect the adjustments to normalize L&P share of Iatan expenses for GMO L&P.

Staff Expert: Keith A. Majors

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 for GMO-MPS and GMO-L&P. 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. Those 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. 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, Staff chose to use the 2007 test year for distribution and transmission for GMO-MPS and GMO-L&P. The production accounts for GMO-MPS and GMO-L&P reflect an upward trend therefore; Staff calculated an average of the 2007 and 2008 balances to account for the increased costs.

In the Company's testimony, several maintenance initiatives were identified that would result in a reduction in maintenance costs. These 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. Adjustments - GMO-MPS: E-17.2, 18-2, 19.2, 20.3, 21.2, 43.2, 44.2, 45.2 and 46.2. Adjustments - GMO L&P: E-22.2, 23.2, 24.2, 25.2, 26.2, 46.2., 47.2, and 48.2.

Staff member Daniel I Beck is providing information regarding the vegetation management and infrastructure inspection programs KCPL-Greater Missouri Operations implemented for the new Commission rules. In essence, the unadjusted test year amounts for maintenance are higher due to the increase 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 be included in the maintenance adjustments. To do so would result in those costs being included in the case over and above an appropriate level.

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 eliminate the depreciation associated with the transportation equipment for MPS and L&P electric. Adjustments E-170 and E-175

Staff Expert: Karen Herrington

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2. Employee Relocation Expense

The Staff submitted Data Request No. 284 asking the Company to "provide former Aquila entities, (MPS, L&P and L&P Steam) employee relocation expense charged to general ledger for the most current 5 years as of December 31, 2007, updated through September 30, 2008”. The Company responded that “Aquila recorded employee expense in account 926000 with resource code 1724” and they listed the employee relocation expense for MPS and L&P through the merger date, July 14, 2008. The Staff noticed that L&P employee relocation expense had a credit balance of ($40,934) for the 2007 test year. This appears to be a reversal entry from the prior year. The Staff removed the credit balance from L&P’s 2007 test year amount and did not make an adjustment for MPS 2007 test year amount for employee relocation expense. (Staff adjustment E-153.4 adjusts L&P 2007 test year employee relocation expense.)

Staff Expert: Paul R. Harrison

3. Lease Expenses

Lease costs are those costs incurred by MPS and L&P for the leasing of its corporate headquarters, equipment and storage units. Staff examined these costs and found that in 2008, lease payments were reduced and made an adjustment to reflect these lower costs in rates.

The Staff submitted Data Request No. 16 asking MPS and L&P to provide a list of all lease agreements (office, vehicle, computers, etc.) charged to Missouri utility operations. The Company’s response to this data request indicates that MPS’s and L&P’s 2007 cost of service included annual lease expense of $1,443,199 and $410,615 for MPS and L&P, respectively. The data for 2008 for the response to this same data request indicates that the annualized 2008 lease expense is $1,010,178 and $334,844 for MPS and L&P, respectively. The Staff used the annualized MPS and L&P lease expense provided in the response to this data request to adjust MPS and L&P lease expense. This annualization resulted in a decrease in the level of MPS and L&P lease expense of $433,022 and $75,771 respectively. (Staff adjustments E-163.1 and E-168.1 adjust MPS and L&P test year 2007 lease expenses)

Staff Expert: Paul R. Harrison

4. Property Tax Expense

Every year, KCP&L-Greater Missouri Operations (GMO) receives a property tax bill from each of the taxing authorities that have jurisdiction over the Company's property. Tax bills for the year are based (assessed) on the property GMO owns on the first day of that calendar 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 in the former Aquila MPS electric and L&P electric territories that was 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 for the total 2008 property tax expense. 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 MPS and L&P 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. 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 MPS and L&P 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's 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 for MPS is E-181.1 and L&P E-187 reflect the annualized levels.

Staff Expert: Karen Herrington

<u>5. Bad Debt Expense</u>

Bad debt expense is the portion of retail revenues MPS and L&P are unable to collect from retail customers by reason of bill non-payment. After a certain amount of time has lapsed, delinquent customer accounts are written off and turned over to a third party collection agency for recovery. If MPS and L&P are 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. Since MPS and L&P bad debt write-offs occur six months after the revenues are billed to the customers, a lagging process was used to compare the write-off ratio over time. Staff calculated the annualized bad debt expense by examining the billed revenues for the twelve months period ending March 31, 2008, and 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 net write-off ratio was derived and applied to Staff's annualized level of retail revenues to obtain the annualized level of bad debt expense for MPS and L&P. It is important to note, the apparent lag time between the net retail sales and actual net write-offs in Staff's calculation is consistent with Company'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-132.1 for MPS and E-135.1 for L&P.

Staff Expert: Kofi Agyenim Boateng

6. Advertising Expense

In forming its recommendation of allowable advertising expenses, Staff relied on the principles the Commission followed in the 1986 Kansas City Power & Light rate case, Case No. EO-2005-0329 and that the Staff has applied since. 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. <u>General</u>: 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).

Based on discussions and GMO and KCPL responses to Staff data requests, the Staff has included for both MPS and L&P levels it believes will be the continuing annual amounts of advertising expense that will be necessary for the provision of utility service by MPS and L&P.

Staff Expert: Bret G. Prenger

<u>7. Dues and Donations</u>

Staff reviewed the list of membership dues paid and donations made to various organizations that MPS and L&P charged to their electric utility accounts during the test year. The Staff accepted GMO's adjustments CS-60 for both MPS and L&P, which removed the test year level of dues and donations recorded above the line.

Staff Expert: Bret Prenger

8. Debit/Credit Card and Electronic Check Payments

Currently, GMO (MPS and L&P) customers who use credit/debit card and electronic check as a form of payment of their utility bills to GMO are charged a convenience fee of approximately $3.95 for each payment transaction to SpeedPay, a third-party payment processor and a subsidiary of Western Union. However, GMO has proposed to eliminate the high cost customer-paid convenience fee program, which is a source of frequent complaints by customers who use the service. GMO plans to replace the current customer-paid program with one similar to what KCPL offers to its customers. In this case the cost of providing the service will be absorbed by the Company, and later built in rates. GMO customers will not be required to pay a direct transaction fee anytime they use credit card, debit card, or electronic check to make payment GMO. The Company believes this arrangement will enhance customer satisfaction, encourage more customers to pay their bills on time to avoid service disconnect. At the same time, the processing fees that SpeedPay will charge GMO is expected to be less than half of what customers currently pay to SpeedPay.

At this time, Staff has not included any amount for this program in its cost of service as there was not enough cost data available at the end of the update, September 30, 2008. However, Staff will review for inclusion any necessary and reasonable cost associated with the program in cost of service during the March 31, 2009 true-up audit.

Staff Expert: Kofi Agyenim Boateng

9. Account Receivable Bank Fees

The selling of accounts receivable results in the Company collecting revenues on an accelerated basis from the 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. As mentioned earlier, the GMO entities were unable to continue an accounts receivable sale program due to poor financial decisions. Prior to its financial downturn, the Company had established a program with Ciesco, an affiliate of Citibank. The program involved a loan from a third party backed by the MPS and L&P divisions' accounts receivables. When the Company began to experience a severe decline in its credit rating, Ciesco terminated the program.

The termination of the accounts receivable program was the direct result of the Company's poor financial condition and has caused a detriment to GMO-MPS and GMO-L&P ratepayers. The loss of the sale of the accounts receivables resulted directly from the problems that Aquila faced in its non-regulated ventures. Based on the Company's past financial problems and the KCPL acquisition, Staff determined an adjustment should be made for the bank fees had the program been in place. KCPL currently sells approximately 57% of its account receivables, which include the account receivables of GMO and L&P. When calculating an appropriate amount for GMO and L&P, Staff used the same percentage based on the receivable balance from July 31, 2008 and December 31, 2008. Adjustment E-133.2.

Staff Expert: Karen Herrington

10. SJLP Merger Transition Costs

L&P's current rates which went into effect on May 27, 2007 reflect the continuation of a 10-year recovery of transition costs incurred during the process of integrating L&P into Aquila's operations as a result of UtiliCorp United, Inc.'s acquisition of St. Joseph Light & Power Company's (SJLP) in Case No. EM-2000-292. The Staff is continuing this treatment in this case. Adjustments E-161.4, MPS and E-166.5, L&P reflects a 10 year amortization of the agreed to $4,959,664 in merger transition costs.

Staff Expert: Paul R. Harrison

11. Miscellaneous Adjustments

There were several adjustments that were required to be made to certain of MPS and L&P 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. Both KCPL and the Staff made these adjustments. These adjustments include:

- E-30.2 - remove South Harper legal fees from the test year expenses from account 546 for MPS
- E-125.3 – eliminate duplicate payment and GUI project settlement from test year expense from account 901 for MPS
- E-150.1 – eliminate non-labor expenses related to acquisition, transition and asset sales from account 921 for MPS
- E-153.1 – remove South Harper legal fees from the test year expenses from account 923 for MPS
- E-156.4 - remove bonus paid related to acquisition, transition and asset sales from account 926 for MPS
- E-161.2 – eliminate duplicate payment and GUI project settlement from test year expense from account 930 for MPS
- E-164.2 – eliminate lease payments for Raytown 750 building that was sold from account 935 for MPS
- E-128.3 - eliminate duplicate payment and GUI project settlement from test year expense from account 901 for L&P
- E-153.1 - eliminate non-labor expenses incurred related to the acquisition, transition, asset sales, etc. from account 921 for L&P
- E-159.6 - remove bonus paid related to acquisition, transition and asset sales from account 926 for MPS
- E-166.2 - remove duplicate payment made in January of 2007 to Burnet, Duckworth and Palmer for L&P
- E-169.2 - eliminate lease payments for Raytown 750 building that was sold for L&P

Staff Expert: Paul R. Harrison

12. Amortization of Demand-Side Managements Costs

The Staff included the deferred DSM costs for MPS and L&P and amortized this deferral over ten (10) years, consistent with the treatment afforded KCPL. Also consistent with the treatment of KCPL's DSM costs, the Staff included a return on these deferrals at KCPL's September 2008 AFUDC rate. The DSM Account 186001 contains costs for DSM programs. At this time, Staff is still reviewing the costs GMO has placed in its demand-side regulatory asset account.

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

13. Vegetation Management and Infrastructure Inspection Program

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

14. 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, and certain forms of insurance reduce shareholder'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. 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 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-MPS and GMO-L&P. The MPS adjustments are E-154.1 and E-155.2 and L&P is E-157.1 and E-158.2 reflects the annualized levels of the insurance costs.

Staff Expert: Karen Herrington

15. 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, Worker’s Compensation, and Auto Liability. Staff analyzed three years of data and determined a three-year average including the period of 2005 through 2007, 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 injuries and claims against the Company. As a result of these injuries, MPS and L&P electric 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. Adjustments E155.1 and E-158.1 reflects a normalized level of costs for injuries and damages.

Staff Expert: Karen Herrington

16. Accounting Authority Orders

In 2007, the city of St. Joseph, Missouri was struck by a significant ice storm. St. Joseph, Missouri is located in the electric service territory formerly designated as Aquila L&P. That ice storm caused considerable damage to the Company's distribution plant in the MPS territory. The Company filed an application with the Commission for an Accounting Authority Order (AAO), to defer the excessive maintenance and operational costs associated with the 2007 storm. That docket was designated Case No. EU-2008-0233. The Commission granted the AAO and ordered that the amortization of the costs associated with the storm begin on January 1, 2008 and will continue for a five year period. Staff issued an adjustment to reflect the annualized amortization amount for the AAO. Adjustment number E-182.

Staff Expert: Karen Herrington

17. Rate Case Expense

Rate case expenses are costs incurred by a utility in preparing and prosecuting its filing for rate relief. In this case, GMO has incurred expenses in conjunction with legal counsel, regulatory consulting, and hired expert witnesses.

Staff utilized GMO records and responses to data requests to determine the appropriate level of rate case expense for inclusion in rates. Amounts from both Outside Services and Regulatory Expense accounts were taken into consideration as GMO determined they were incurred for the current rate case. Staff requested actual billings and invoices from GMO to examine the reasonableness of the costs incurred. Staff has included in this case actual amounts incurred through September 30, 2008 that were determined to be reasonable and relate to the preparation of the GMO electric (MPS and L&P electric) rate case filing.

Staff removed costs GMO incurred for the production of a depreciation study of MPS and L&P plant that wasn't used for this filing. The Staff transferred these costs from rate case expense to other regulatory costs, and will amortize them over a 5-year period consistent with the maximum time period over which utilities are required to file depreciation studies.

As GMO incurs additional rate case expense, Staff will include actual costs deemed to be reasonable and prudent to develop an amount of on-going rate case expense level which it will recommend be recovered in MPS and L&P electric rates. The Staff is normalizing rate case expense over two years as proposed by GMO in this case.

Staff Expert: Bret G. Prenger

18. 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.

The PSC Assessment for MPS and L&P electric operations was annualized using the latest assessment available for the current fiscal year (FY-2009) on information obtained from the Commission's records. The annualized assessments were compared to the 2007 PSC Assessment amounts included in the test year to form the basis of Staff adjustments E-162.2 (Electric) and E-158.2 (MPS).

Expert: Bret G. Prenger

VIII. Depreciation Summary

The Staff conducted a depreciation study of the capital assets of the electric and industrial steam operations of KCP&L-Greater Missouri Operations Company (GMO), including an analysis of the accumulated reserve for depreciation. GMO has two operating divisions—the former Aquila Networks-MPS division (GMO-MPS) and the former Aquila Networks-L&P division (GMO-L&P). GMO-L&P has both electric and industrial steam operations. GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam each have separate, distinct, and independent Commission-ordered depreciation rates; therefore, the Staff analyzed depreciation rates for each in its depreciation study. Based on its study, the Staff recommends separate depreciation rates for GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam which, when applied to the plant-in-service (on a Missouri Adjusted Jurisdictional basis) as of September 30, 2008, generated the depreciation expenses of GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam used in developing the Staff's revenue requirements for each—GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam. This was necessary since the customers of GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam each have rates based on distinct, independent, and separate tariffs which generate separate revenue requirements.

Staff's proposed depreciation rates for GMO-MPS would decrease the currently ordered annual depreciation expense from approximately $50.5 million to $45 million, a reduction of approximately $5.5 million.

Staff's proposed depreciation rates for GMO-L&P electric would decrease the currently ordered annual depreciation expense from approximately $11.5 million to $10.4 million, a reduction of approximately $1.1 million.

Staff's proposed depreciation rates for GMO-L&P industrial steam would decrease the currently ordered annual depreciation expense from approximately $0.7 million to $0.6 million, a reduction of approximately $0.1 million.

Schedules 3-1 and 3-2 are listings, by plant account, of the Staff's proposed depreciation rates for GMO-MPS and GMO-L&P electric in Case No. ER-2009-0090, and Schedule 3-3 is a listing, by plant account, of the Staff's proposed depreciation rates for GMO-L&P industrial steam in Case No. HR-2009-0092.

Schedules 4-1, 4-2 and 4-3 are listings, by plant account, of Staff's proposed depreciation parameters for each—GMO-MPS, GMO-L&P electric and GMO-L&P industrial steam in Case No. ER-2009-0090 and Case No. HR-2009-0092, respectively. Those schedules also include a comparison of Staff's recommended new depreciation rates to the current Commission-ordered rates (ordered in Case No. ER-2007-0004 effective May 27, 2007) for each division, respectively, which include the Company's corporate plant accounts and they offer a comparison to the depreciation rates for each division, respectively, that are developed in the Company's 2008 depreciation study, excluding the Company's corporate plant accounts. The Company failed to submit to Staff a depreciation study of its corporate plant accounts and a historical database of these plant accounts (Schedule 9-1), in accordance with 4 CSR 240-3.175(1)(B)2. The Company's corporate plant accounts, known as ECORP after Aquila Inc.'s acquisition by Great Plains Energy, will be discussed in more depth below.

Schedules 5-1, 5-2, and 5-3 are listings, by plant account (excluding the corporate plant accounts) as of December 31, 2007, of the accumulated reserve for depreciation and theoretical reserve amounts for each—GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam in Case No. ER-2009-0090 and Case No. HR-2009-0092, respectively.

Staff's study notes an over-accrual of the accumulated reserve for depreciation (excluding ECORP) of approximately $145.3 million, $72.5 million, and $0.3 million for each--

GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam, respectively, for a Company total of over $218 million.

Staff's calculation of the ECORP accumulated reserve for depreciation, as of September 30, 2008, is shown in Schedule 2. Staff has adjusted the Company's ECORP reserve amounts (Schedules 8-1 and 8-2) to include approximately $4.2 million of depreciation accrual that would exist if the Company had continued use of its authorized depreciation rates on all accounts (Schedules 9-2 through 9-6), approximately $4 million of reserve deficiency created by the occurrence of premature retirements after the Company was acquired by Great Plains Energy (Schedules 10-1 through 10-3), and an assignment (on a weighted average per reserve account) equal to the reduction of the reserve overstatement that is currently assigned to GMO-MPS and GMO-L&P electric rather than the ECORP accumulated reserve for depreciation (Schedules 11-1 through 11-6 and 12-1 through 12-4). Currently, this reduction of the reserve overstatement is shown assigned to these two divisions as UCU Common General Plant.

Staff's total recommended adjustment to ECORP accumulated reserve for depreciation is approximately a $10.7 million reduction including the reduction of the reserve overstatement for GMO-MPS and GMO-L&P of $14,076,021 and $4,744,482, respectively, using a weighted average of each ECORP reserve account's balance as of September 30, 2008, an increase of the reserve for GMO-MPS and GMO-L&P of $2,966,218 and $976,648, respectively, and an increase of the reserve for GMO of $4,221,178. Staff's review of the Company's records through December 31, 2008 found additional reserve deficiencies, of approximately $1 million, from additional premature retirements, that cause three of the five ECORP accounts to have negative reserve amounts. ECORP accounts 390.00, Structures and Improvements, 391.00, Office Furniture, and 397.00, Communications Equipment, all have negative reserves at

December 31, 2008. Only ECORP accounts 391.02, Computer Hardware and 391.04, Computer Software, have positive reserve balances. Staff will address these amounts in its true-up filing.

Staff recommends that a portion of the Company's $218 million over-accrual could be assigned in the future to ECORP to address the reserve reductions noted above.

Schedule 1 is the Company's 2008 depreciation study submitted to Staff in September 2008. As noted above, the Company's corporate accounts are not included in the Company's 2008 depreciation study.

A. Depreciation

Depreciation is the loss, not restored by current maintenance, which is due to all factors causing ultimate retirement of the property. These factors include wear and tear, decay, inadequacy, obsolescence, changes in the art, and requirements of public authorities.

The purpose of depreciation in a regulatory setting is to recover the cost of capital assets over the useful lives of the assets. The depreciation rate for each plant account is designed to recover, over the average service life of the assets in that account, the original cost of the assets plus an estimate for any cost of removal less scrap value. Annual depreciation expense for a plant account is the depreciation rate for that plant account multiplied by the balance of plant in that account. The annual depreciation expense returns to the Company's shareholders a portion of the costs of the capital assets. In a regulatory setting this return is commonly referred to as a return of equity. The remaining portion of the costs of the capital assets of the Company (net plant-in-service) is returned to the Company's shareholders in the future. The Company is permitted during this period to earn a return on the capital assets in rate base, commonly referred to as a return on net plant-in-service, a component of rate base. In a regulatory setting this return is commonly referred to as a return on equity.

B. Depreciation Study

Staff used the straight line method, broad group-average life procedure and whole life technique depreciation system for its depreciation study of the Company's capital assets. Staff has consistently used the whole life technique in developing depreciation rates that reflect expected average service lives. The whole life technique does not include an adjustment factor to address over- or under-accruals in the accumulated reserve for depreciation. Staff uses the following formula to calculate a depreciation rate for each plant account:

Depreciation Rate = (100 % -Net Salvage %) ÷ (Average Service Life).

This is consistent with the Commission's Depreciation Rate Formula from its Report and Order in The Empire District Electric Case No. ER-2004-0570. As shown in the formula, average service life and net salvage percentage are the depreciation parameters used to determine the depreciation rate. The Staff calculated depreciation rates for each plant account based on the average service life and net salvage percentage determined applicable to each account, as shown for GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam in Schedules 4-1, 4-2, and 4-3, respectively. That determination requires engineering experience and informed judgment and is addressed in detail below.

C. Average Service Life

For each plant account, the average service life (ASL) is the expected period, in years, of the useful service of each unit of property in that account, (e.g. electric poles), regardless of when that unit was first put into service—its placement date. An account's ASL is developed in four steps. The first step is to review historical mortality data and historical salvage/cost of removal data. The data are checked for reasonableness and to ensure sufficient data exist to perform a statistically significant analysis. In addition, Staff reviews the data to determine if retirements recorded in one historical database are also recorded in the other historical database. The second step is to gain familiarity with the facilities and to discuss current trends and developments that may influence the useful life of plant-in-service with operations' personnel, engineers, accountants, and other depreciation experts. Current developments such as technological changes, environmental regulations, regulatory requirements, or accounting changes can all affect the average service life of property in an account. Different vintages of plant being manufactured from different materials, changes in installation practices, or the development of a life extending maintenance procedure are some examples of factors contributing to changes in average service lives. Difficulty in constructing new generation plant has led utilities to choose to spend the incremental costs of increasing the capacity of existing plants or extending the life of existing plants; i.e., expenditures at the Sibley Production Plant has extended the life of its original generating units.

The third step is to perform a statistical analysis of the retirement experience of each utility plant account, followed with analysis of the results for reasonableness for the type of plant in question. To evaluate the retirement experience of the Company's plant accounts, depreciation software used by Staff analyzes historical plant data by calculating the ratio of retirements to exposures by age, then solving for the percent surviving by age to develop a survivor curve for an account. The required data are plant additions in dollars by year, or vintage, and retirements from each vintage in dollars by year. The exposures at a given age are the dollars remaining from the various vintages that have lived to that age. The retirement ratio is the dollars retired during an age interval divided by the exposures at the beginning of that interval. The survivor ratio is then calculated by subtracting the retirement ratio from "1". Multiplying each successive survivor ratio by the percent surviving of the previous age will generate a survivor curve. This original survivor curve can then be smoothed and fitted to an empirically developed statistical model known as the Iowa curves. The Iowa curves are widely accepted models of the life characteristics of utility property. The system of Iowa curves is a family of 176 types of utility and industrial property. The curves were developed at the Iowa Engineering Experiment Station at what is presently known as Iowa State University. The Iowa curves were first published in 1935 and reconfirmed in 1980. Smoothing the original survivor curve by fitting it to an Iowa curve eliminates irregularities and extrapolates stub curves to zero percent. The original survivor curve is mathematically and visually matched with various Iowa curves to determine which has the most appropriate fit, either for a significant portion of the curve or just a specified portion of the curve. The average service life of an account's original survivor curve is estimated as the area under the selected Iowa curve. The fourth step is using engineering experience and informed judgment to the aggregate of the first three steps in the process to assign an appropriate ASL for each plant account.

Staff's life estimates for GMO MPS production plant accounts include the Jeffrey Energy Center, located in Kansas, and the Sibley Generating Plant. The Company has an 8% ownership of the Jeffrey Energy Center. Staff's life estimates for GMO-L&P production plant accounts include the Lake Road Generating Plant and the Iatan I Generating Plant. The Company has an 18% ownership of the Iatan I Generating Plant. Because of data limitations with Jeffrey Energy Center production plant accounts, GMO- L&P electric accounts, GMO-L&P industrial steam production accounts, and GMO ECORP accounts, Staff recommends its life analyses of the GMO-MPS accounts be utilized to set depreciation rates for these respective functional accounts. Given that the plant assets in the respective functional accounts should be similar, the historical retirement activity should also be similar. The GMO ECORP accounts are the former Aquila, Inc. Corporate plant accounts. They will be discussed in more depth below. The short history of data and limited retirement history for the Jeffrey Energy Center accounts limit its statistical review. Data limitations for GMO-L&P referred to above include placements of vintages prior to 1979 in the data file are not recorded until 1979 and no retirements, from those vintages, recorded until 1979. This results in some plant being almost eighty years of age with no retirements occurring. The results of such data gaps can produce artificially long ASL's.

Staff recommends its life analysis of GMO-MPS account 366.00 Distribution Underground Conduit, be used for GMO-L&P electric account 357.00, Transmission Underground Conduit, as GMO-MPS does not have any assets in account 357.00.

Staff's review of the Company's booking of plant assets for the Crossroads Energy Center found that the Company is not booking these units consistently with other combustion turbines it is currently operating and including in rate base.

Staff recommends the Company review its unit property catalog for proper and consistent placement of these units, such that a depreciation analysis in the future reflects similar units of property in account 343.00, Prime Movers and account 344.00, Generators, respectively.

Staff recommends its life analyses of GMO-L&P industrial steam's distribution accounts be used to set depreciation rates for those accounts.

Staff recommends that the Company keep a separate accounting of its amounts accrued for recovery of its initial investment in plant from the amounts accrued for the cost of removal.

As noted earlier the average service life is just one of two factors determining a given depreciation rate. The second factor, net salvage percentage, is discussed next.

D. Net Salvage Percentage

The second factor in determining a given depreciation rate is the net salvage percentage. Consideration is given to the future net salvage (or cost or removal) that property in an account may experience.

Net Salvage = Gross Salvage -Cost of Removal

Gross salvage is the recovered marketable value of retired plant. Cost of Removal is the cost associated with the retirement and disposition of plant from service. Negative net salvage occurs when the cost of removal exceeds gross salvage. A negative net salvage is commonly referred to as an expense or net cost of removal and a negative net salvage percentage is called a net cost of removal percentage. Today, most accounts experience a net cost of removal; therefore the net salvage percentage in the depreciation calculation is negative which results in an increase to overall depreciation expense.

Net salvage percentages were developed by dividing the experienced net cost of removal by the original cost of plant retired during the same time period to calculate the net cost of removal percentage realized by the Company. This is consistent with the Commission's policy for net salvage from its Report and Order in The Empire District Electric Case No. ER-2004-0570. Staff performed rolling 5-year band analysis for deriving net cost of removal percentages. This review showed that in some accounts there was no recent history of costs and that, in other accounts, timing of retirements and costs produce unreliable estimates of net cost of removal percentages; i.e., GMO-L&P electric plant account 355.00, Poles and Fixtures, had an average net salvage percentage of negative 1434% for the 5-year period of 2003-2007. Five years prior, the account had an average net salvage percentage of positive 10% for the 5-year period of 1998-2002. From the earlier 5-year average to the most recent 5-year average the account experienced positive 8%, positive 2%, negative 9% and negative 8%, respectively. Future Net Salvage percentage estimates from the Company's 2008 Depreciation Study, performed by Dr. Ron White of Foster Associates, were also reviewed by Staff and are recommended by Staff to be used to develop Staff's proposed depreciation rates. For example, Dr. White's estimate of a negative 30% (rounded) for the L&P electric plant account 355.00, Poles and Fixtures, appears to be more aligned with the cost of removal trend actually occurring for this account. Additionally, net salvage percentages were capped by Staff at negative 100% by account. Both positions are consistent with those taken by Staff in the Company's 2005 rate case, Case No. ER-2005-0436. For all of the Company's production accounts, the net salvage percentage reflects an estimate of future interim cost of removal only, as terminal cost of removal is not collected until final retirement of a unit.

Dr. White noted on page 6 of the Company's 2008 Depreciation Rate Study, "[t]his study provides the foundation and documentation for recommended changes in the depreciation accrual rates used by Aquila-MPS and L&P (Electric and Industrial Steam) operations. The proposed rates are subject to approval by the Missouri Public Service Commission." Dr. White's study is an actuarial analysis and engineering study of utility property owned and operated by the Company, given the most recent utility property records. Staff notes that the Company has chosen not to adopt the results and proposed depreciation rates from their 2008 Depreciation Study, shown in Schedule 1.

Depreciation software uses the selection of a specific Iowa curve and net salvage percentage for each plant account to calculate the account's theoretical accumulated reserve for depreciation, discussed next.

E. Analysis of Accumulated Reserve for Depreciation

Another analysis performed with a depreciation study is an examination of the adequacy of the accumulated reserve for depreciation and identification of any reserve over- or under-recovery. This analysis illustrates whether prior depreciation estimates have differed significantly from actual experience. An analysis of the accumulated reserve for depreciation reserve is performed by comparing the existing accumulated reserve for depreciation as of a certain date (December 31, 2007) to a theoretical accumulated reserve for depreciation, given the revised depreciation parameters selected for each account, as shown for GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam in Schedules 5-1, 5-2, and 5-3, respectively. Staff used the December 31, 2007 reserve balances shown in the Company's 2008 depreciation study instead of reserve amounts shown in the Company's response to Staff Data Request No. 27, as the Company noted in an e-mail to Staff on January 22, 2009 that the balances in Data Request No. 27 include Retirement Work in Progress (RWIP) and the balances in the [2008] depreciation study do not (Schedule 6). Further discussion on RWIP can be found in the report section by Staff witness, Karen Herrington. (Similarly, the Company explains plant accounts waiting final unitization of a work order may cause a negative plant-in-service balance, i.e., GMO-MPS account 398.00, Miscellaneous Equipment, as noted in Schedule 7, and is demonstrative of the clearing process rather than an absolute balance.)

A depreciation reserve account is the amount for plant investment and net cost of removal that has been recovered in depreciation rates over the life of the capital assets, reduced by retirement amounts, costs of removal experienced, and transfers out, and increased by actual salvage proceeds collected, and transfers in. The aggregate of the depreciation reserve accounts is known as the accumulated reserve for depreciation. The theoretical accumulated reserve for depreciation amount can be viewed as the level of accumulated depreciation reserve that would exist today if the selected depreciation parameters had been used since the inception of placing plant in service. If the amount of the actual accumulated reserve for depreciation is more than the theoretical amount, an over-accrual is noted. Conversely, if the actual accumulated reserve for depreciation is less than the theoretical amount, an under-accrual is noted.

The need for, the magnitude of, and the timing of an adjustment should be based upon consideration of several factors: the characteristics of the account, the causes of the difference, and the year-to-year volatility of the accumulated provision for depreciation as well as the magnitude of the imbalance. Future service life cannot be estimated to a degree of certainty that guarantees that the actual life will not be different. In fact, the depreciation estimation process is dynamic and it is possible that the currently determined ASL that Staff is recommending will differ from the ASL that occurs. With the possible exception regarding ECORP noted below, no adjustment to the reserve is proposed by Staff at this time. After another depreciation study is conducted, trends in the over-accrual may be identified and appropriate steps, if necessary, can be implemented. Consideration of the ECORP accounts' accumulated reserve for depreciation should also be included in the balancing of the Company's over-accrual. ECORP accounts will be discussed below. Evaluation of these over-accrued reserves and ECORP under-accrued reserves should be made in future rate filings and, if appropriate, addressed by Staff at that time.

F. ECORP Accounts

In the Staff's direct testimony of the Company's last rate case, ER-2007-0004, Staff recommended that "the currently ordered depreciation rates be retained but that Staff perform a complete depreciation study in the Company's next rate case." The Company indicated it intended to complete its next full depreciation study by early 2008. The Company submitted a depreciation study to Staff in September 2008; however, its depreciation study of its corporate assets was never submitted and the Company never filed for a waiver of the requirement to do so.

Staff also noted in its direct testimony in the last rate case that there was a need to review the depreciation rates of the combustion turbines. However, Staff did not perform that review at that time due to a lack of sufficient operating experience, as the South Harper generating units were too new to have retirement history data, and the Greenwood generating units were leased units, thus their prior in-service experience was not included in actuarial plant data.

In the context of the present rate case, ER-2009-0090, Staff examined the depreciation parameters and plant accounts of the combustion turbines being operated by the Company.

The Company provided Staff historical mortality and salvage/cost of removal data in September of 2008 for all plant accounts, except its corporate plant accounts. Staff requested this data in questions (1) and (2) of Staff's Data Request No. 258 (Schedule 9-1). The Company's response to this data request was, "Data requested in questions 1 and 2 are prepared and incorporated as part of depreciation study projects. No corporate plant depreciation study was completed for 2007."

In the absence of historical mortality and salvage/cost of removal data for the Company's corporate plant accounts, Staff did a limited review of the activity and balances from corporate plant accounts and accumulated depreciation reserves from monthly entries in the Company's General Ledger and sub-ledger for November 2006 to December 2008 for these accounts, as provided in the Company's response to Staff's Data Request No. 258 (including supplemental requests, updates, and revisions) Schedules 9-1 through 9-6. Staff also reviewed information regarding corporate assets provided in the Company's response to Staff's Data Request No. 247 (including supplemental requests, updates, and revisions) Schedules 8-1 and 8-2 and

Schedules 10-1 through 10-3 and data received in response to Staff's Data Request No. 27 regarding these accounts specific to the books of GMO-MPS and GMO-L&P Schedules 11-1 through 11-6 and Schedules 12-1 through 12-4).

Staff's limited review revealed several areas of concern that will be identified below.

The first concern is related to the Company's decision to cease use of the authorized depreciation rates for several of its corporate accounts, which caused an understatement of the reserve of approximately $4.2 million, and an equal overstatement of rate base.

Account 391.05, Computer Systems Development, account 394.00, Tools, Shop and Garage Equipment, and account 397.00, Communications Equipment are currently fully accrued. Staff recommends a 0% depreciation rate for these accounts (Schedules 3-1, 3-2, and 3-3). Reinstatement for the periods the Company failed to use the authorized depreciation rates creates an additional reserve of approximately $4.2 million for these accounts, equal to the amount noted above. [Reserve Adjustment Nos. R155.2, R157 R158, and R160, R127.2, R129, R130, and R132, and R95.2, R97, R98, and R100 for GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam, respectively.]

The second concern is related to the early retirement of plant as a consequence of Aquila's acquisition by Great Plains Energy. The early retirement of plant creates a reserve deficiency in some of the ECORP accounts, as of September 30, 2008. This reserve deficiency is created when plant dollars are retired from the plant accounts and an equal amount is removed from the accumulated reserve for depreciation, without sufficient accrual over the life of the plant. In mass asset accounting, some plant may not reach the ASL of the account and other plant may reach a life extending beyond the ASL, resulting in, on average, the service life of the plant. However, when an unusual retirement occurs – such as when a utility's acquisition by another utility results in some plant no longer being needed and retired prematurely -- a detriment to the current ratepayers is created if ratepayers are required to make up the deficiency. GMO's early plant retirement results in deficiencies of approximately $3 million for GMO-MPS and approximately $1 million for GMO- L&P, as of September 30, 2008. Reinstatement of the approximately $4 million to the reserve for reserve deficiencies for these accounts will avoid detriment to the current ratepayers for transactions that occurred only because of GPE's acquisition of Aquila, Inc. [Reserve Adjustment Nos. R155.1 and R156.1, R127.1 and R128, and R95.1 and R96 for GMO-MPS, GMO-L&P electric, and GMO-L&P industrial steam, respectively.] Further discussion on ratepayer detriment and these premature retirements of ECORP plant can be found in the report section by Staff witness, Charles R. Hyneman, CPA.

A review of the activity and balances for the reserves through December 31, 2008 shows that additional reserve deficiencies of approximately $1 million, in total, occur as additional plant is retired early through year-end. Currently, ECORP account 390.00, Structures & Improvements, has a negative amount of accumulated reserve for depreciation. And, as noted earlier, three of the five ECORP accounts for which Staff is recommending depreciation rates have a negative amount of accumulated reserve for depreciation, as of December 31, 2008. Identification of these negative ECORP reserves is the basis for Staff's consideration of balancing the Company's over-all over-accrual through a transfer of a portion of the $281 million over-accrual to the reserves for the ECORP accounts. As noted above, evaluation of these ECORP under-accrued reserves and the Company's over-accrued reserves should be made in future rate filings and, if appropriate, addressed by Staff at that time.

The third concern is related to the reserve deficiencies that exist specific to the books of GMO-MPS and GMO-L&P, of approximately $14.1 million and $4.7 million, respectively.

These are not assigned to ECORP accounts, but are an amount reflecting an overstatement of Aquila, Inc.'s allocation of its corporate accumulated reserve for depreciation to Missouri where the corporate depreciation rates were higher than Missouri's authorized depreciation rates for corporate accounts.

A fourth concern is raised by the Company's failure to use authorized depreciation rates per 4 CSR 240-20.030, the failure of the Company to submit a depreciation study or request a waiver from the rules, and the Company's failure to submit a complete database per 4 CSR 240-3.175.

The fifth concern is related to the need for tracking of amounts accrued for the cost of removal component of the annual depreciation accrual. In its Report and Order issued January 11, 2005, in the remand of Case No. GR-99-315, the Commission directed "that Laclede Gas Company keep a separate accounting of its amounts accrued for recovery of its initial investment in plant from the amounts accrued for the cost of removal." (Ordered Paragraph 6) This is consistent with the Commission's Report and Order in AmerenUE's Case No. ER-2007-0002 and in the Commission's Order Concerning Applications for Rehearing and Motions for Clarification or Reconsideration in The Empire District Electric Company's Case No. ER-2004-0570.

G. Recommendations

Staff recommends that the Commission order the depreciation rates proposed in Schedules 3-1 and 3-2 for GMO-MPS and GMO-L&P electric, respectively. (Schedule 3-3 for GMO-L&P industrial steam will be addressed in the Company's Case No. HR-2009-0092.)

Staff recommends the Company be required to use the currently authorized Missouri depreciation rates for ECORP accounts until the effective date of this order and reflect the additional depreciation accrual on its books.

Accordingly, Staff recommends imputed depreciation accrual of approximately $4.2 million be added back to the reserves of the respective ECORP accounts For GMO the amounts to increase ECORP reserve include $7,142 for account 391.02, Computer Hardware, $4,168,503 for account 391.05 Computer Systems Development, $11,497 for account 394.00, Tools, Shop, and Garage Equipment, and $34,036 for account 398.00, Miscellaneous Equipment. Staff also recommends this additional depreciation accrual be transferred to the reserve for ECORP account 390.00, Structures & Improvements, which is currently negative and, thus, under-accrued.

Staff recommends that to avoid a detriment to current ratepayers, reserve deficiencies of approximately $4 million for retirement of plant due to the Company's acquisition by Great Plain Energy be added back to the respective ECORP reserve accounts. For GMO-MPS the amounts to increase ECORP reserve include $7,331 and $2,958,887 for accounts 391.02, Computer Hardware, and 391.04, Computer Software, respectively. For GMO-L&P the amounts to increase ECORP reserve include $2,414 and $974,234 for accounts 391.02, Computer Hardware, and 391.04, Computer Software, respectively.

Staff recommends that the reserve deficiencies that exist specific to the books of GMO-MPS and GMO-L&P of $14,076,021 and $4,744,842, respectively, be included in the ECORP accumulated reserve for depreciation using a weighted average of each ECORP reserve account's balance as of September 30, 2008.

Staff recommends that both GMO-MPS and GMO-L&P electric keep a separate accounting of their amounts accrued for recovery of their initial investment in plant from the amounts accrued for the cost of removal.

Staff Expert: Rosella L. Schad

IX. Current and Deferred Income Tax

A. Current Income Tax

Current income tax for this case has been calculated by the Staff consistent with the methodology used in MPS's and L&P's last rate case, Case No. ER-2007-0004. 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 IRS in determining taxable income. Current income tax reflects timing differences consistent with the timing required by the IRS. The tax timing differences used in calculating taxable income for computing current income tax are as follows:

Add Back to Operating Income Before Taxes:

- Book Depreciation Expense
- 50% Meals and Entertainment Disallowance
- Contribution in Aid of Construction
- Advances for Construction

Subtractions from Operating Income:

- Interest Expense – Weighted Cost of Debt X Rate Base
- Tax Straight-Line Depreciation
- Tax Depreciation over Straight Line Tax
- IRS Section 199 Domestic Production Activities

B. Straight Line Tax Depreciation

Annualized book depreciation is a result of multiplying the plant investment at September 30, 2008, the end of the update period used by the Staff for this proceeding, by the book depreciation rates being recommended by Staff witness Rosella L. Schad of the

Engineering and Management Services Department. Straight line tax depreciation represents the tax deduction for book depreciation for a regulated utility for ratemaking purposes.

The IRS allows a regulated utility, like all corporations, to use an accelerated depreciation method in calculating its current income tax liability. However, with regard to a regulated utility, Congress intended for the additional cash flow (lower current income tax), resulting from an accelerated depreciation method, to be retained by the utility. As a result, under IRS rules for a regulated utility, the additional deduction resulting from the use of an accelerated depreciation method cannot be reflected in rates. Ratepayers receive the tax deduction for depreciation expense over the same period used for book accounting purposes.

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

Staff Expert: Paul R. Harrison

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

Staff Expert: Paul R. Harrison

E. Deferred Income Tax and Amortization

MPS's and L&P's deferred income tax reserve represents, in effect, a prepayment of income taxes by MPS's and L&P's customers. As an example, because MPS and L&P are 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. The net credit balance in the deferred tax reserve represents a source of cost-free funds to MPS and L&P. Therefore, MPS's and L&P'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.

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 to ratepayers (amortize) the excess deferred taxes over the approximate depreciable book life of the property.

The Staff's income tax calculation, for MPS and L&P in this current case, reflects an amortization of excess deferred taxes resulting from the reduction in the federal tax rate in 1986

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.

The Staff has also included the accumulated deferred taxes related to the 1990 and 1992 Accounting Authority Orders (AAO) approved by the Missouri Public Service Commission in Case Nos. EO-91-358 and EO-91-360 for the MPS division in Rate Base Schedule 2. These AAO's deferred the depreciation expenses and carrying costs associated with the life extension construction and coal conversion project at the Sibley Generating Station.

Staff Expert: Paul R. Harrison

X. Fuel Adjustment Clause

In GMO's last rate increase case, Case No. ER-2007-0004, before Aquila was acquired by GPE, the Commission approved a fuel adjustment clause ("FAC") for GMO with differing base energy costs for MPS and L&P. Determined separately for MPS and L&P, the FAC allows for the difference between the costs Aquila actually incurs for fuel and purchased power over six-month periods (accumulation periods) and the costs for fuel and purchased power included in its existing rates to be recovered over twelve-month periods (recovery periods) through either a positive or negative adjustment, i.e., the effective rates to customers may increase or decrease. This positive or negative adjustment is called the Cost Adjustment Factor (CAF).

A timeline for the FAC, assuming the Commission approves GMO's request to continue its FAC, is shown in Appendix 5. The CAFs have changed twice since the FAC went into effect, and GMO's third CAF change request is pending at the time of this report. To date, GMO's CAFs have increased with each request, each increase signifying a correlating increase in GMO's fuel and purchased power costs.

The Staff completed a prudence review of GMO's costs that are the subject of its FAC for the first twelve-month period (June 2007 though May 2008) after the Commission approved GMO's FAC (Case No. ER-2007-0004), and the Staff filed its prudence report in Case No. EO-2009-0115 on December 1, 2008.

In its *Report and Order* in Case No. ER-2007-0004, the Commission concluded that it was reasonably necessary to require, in connection with establishing a rate adjustment mechanism for GMO, that GMO develop a heat rate and/or efficiency testing schedule and plan. In Case No. EO-2008-0156 the Commission found the heat rate schedule and testing plan GMO filed on November 9, 2007, as amended and supplemented on November 27, 2007, complies with the heat rate testing requirement in Commission Rule 4 CSR 240-3.161(2)(P) and approved it.

GMO's heat rate and/or efficiency testing results are the baseline against which to measure the future efficiency of the units. Staff has reviewed the results of the completed heat rate and efficiency tests on the following units: Sibley 1, 2, and 3; Greenwood 1, 2, 3, and 4; Ralph Green 3; South Harper 1, 2, and 3; Lake Road 2, 3, and 5; Lake Road boiler 8; and Jeffrey Energy Center 1. The test methodologies utilized were consistent with the plan approved in Case No. EO-2008-0156. The test results and associated data appear reasonable. Heat rate and/or efficiency testing is still scheduled for Nevada; KCI 1 and 2; Lake Road 1, 4, 6, and 7; Lake Road boilers 1, 2, 3, 4, and 5; Jeffrey 2 and 3, and Iatan 1.

Based on Staff's review of the direct testimony filed by GMO in this case, GMO's fuel and purchased power costs; the experience and knowledge Staff has gained in reviewing

FAC proposals, FAC tariff filings and conducting its prudence review of GMO's FAC; and the criteria regarding FACs the Commission has stated in orders in rate cases, Staff believes GMO should continue to have a FAC; however, the Staff recommends the Commission take the following actions regarding GMO's FAC:

(1) Clarify that its *Report and Order* in Case No. ER-2007-0004 directed that off-system sales costs and revenues should flow through GMO's FAC, or if the Commission finds that this was not its intention in Case No. ER-2007-0004, the Commission should order that GMO's FAC be modified to flow through off-system sales costs and revenues;

(2) Modify GMO's FAC to include SO_2 emission allowance revenues to flow through GMO's FAC;

(3) Modify GMO's FAC tariff sheet to list all the expenses and revenues that flow through the FAC;

(4) Modify GMO's FAC to, when GMO's participation in the Southwest Power Pool ("SPP") regional transmission organization ("RTO") begins (anticipated to commence during the pendency of this case), include GMO's SPP energy imbalance market settlements and revenue neutrality uplift charges to flow through GMO's FAC ;

(5) Modify GMO's FAC from having a single base to having summer (June through September) and winter (October through May) bases;

(6) Change the base of GMO's FAC to reflect the Commission's decisions on the foregoing Staff recommendation and the fuel and purchased power costs the Commission determines for setting GMO's general rates;

(7) To aid in the FAC tariff, prudence and true-up reviews, order GMO to submit to the Staff the following:

- As part of the information GMO submits when it files a tariff to change its CAF, GMO's calculation of the interest included in the proposed CAF;
- To include with the monthly reports required by 4 CSR 240-3.161(5), GMO's SPP energy imbalance market settlements and revenue neutrality uplift charges;
- A copy of each and every coal and transportation contract GMO has that is in effect;
- Within 30 days of the effective date of the contract, a copy of each and every coal and transportation contract GMO enters into;
- A copy of each and every natural gas contract GMO has that is in effect;
- Within 30 days of the effective date of the contract, a copy of each and every natural gas contract GMO enters into;

- A copy of each and every hedging contract GMO has executed;
- A copy of each and every GMO present hedging policy;
- Within 30 days of any change in a GMO hedging policy, a copy of the changed hedging policy;
- Within 30 days of the effective date of the contract, a copy of each and every hedging contract GMO enters into;
- A copy of GMO's internal policy for participating in the SPP Energy Imbalance Services (EIS) market, including any GMO sales/purchases from that market;
- If GMO revises any internal policy for participating in the SPP EIS market, within 30 days of that revision, a copy of the revised policy with the revisions identified; and
- In addition to supplying the information required by 4 CSR 240-3.190(3) for any accidents occurring at a power plant involving serious physical injury or death or property damage in excess of $100,000, GMO supply the information for every incident at a power plant.

As a part of its prudence review of GMO's fuel and purchase power activities filed on December 1, 2008 in Case No. EO-2009-0115, Staff noted that it found no imprudence regarding off-system sales margin made by GMO. Staff received a call from Mr. Tim Rush of KCPL explaining that GMO had not included off-system sales in its FAC. There are two reasons that Staff believes off-system sales margin is included in GMO's FAC. First, off-system sales margin was included in the calculation of the base fuel and purchased power cost for GMO's FAC. Second, in response to the Staff' request that the Commission clarify whether SO_2 allowance costs were flowed through Aquila's FAC because the matter was not explicitly addressed in the Commission's *Report and Order* in Case No. ER-2007-0004, the Commission stated in its *Order Rejecting Tariff, Granting Clarification, Directing Filing and Correcting Order Nunc Pro Tunc* that it had not expressly addressed this because no party had argued that SO_2 should be excluded. Like SO_2 allowance costs, no party argued off-system sales margins should be excluded and, as reflected in its *Report and Order* in that case, the Commission recognized GMO, in the testimony of its witness Dennis R. Williams, had included off-system sales margin in the FAC it requested.

As to the first reason, off-system sales margin was included in the calculation of the base fuel and purchased power cost for GMO's FAC, it follows that off-system sales margins should also be included in the calculation of the fuel and purchased power costs during a FAC accumulation period. If not, and fuel and purchased power costs during an accumulation period exactly matched the fuel and purchased power costs used in setting the base, there would be a positive CAF, even though GMO would not have incurred higher fuel and purchased power costs over the accumulation period than what were included in "permanent" rates, i.e., GMO would be receiving a "windfall." This reason alone is sufficient basis for the Staff's position that GMO's FAC includes off-system sales margin.

As to the second reason, Staff requested the Commission clarify its *Report and Order* in Case No. ER-2007-0004 regarding whether SO_2 allowance costs were to flow through GMO's FAC because the Commission was silent on the issue in its *Report and Order* and parties, particularly the Staff and GMO, disagreed as to whether SO_2 allowance costs were to flow through GMO's FAC. The Commission addressed the Staff's request for clarification in its *Order Rejecting Tariff, Granting Clarification, Directing Filing and Correcting Order Nunc Pro Tunc*, where the Commission stated:

> The Commission did not specifically list SO_2 emission allowance costs as costs that should flow through the fuel adjustment clause, because no party, including Staff, argued for their exclusion.

As stated earlier, GMO, in the testimony of its witness Dennis R. Williams, had included off-system sales margin in the FAC it requested and the Commission noted on page 30 of its *Report and Order* in Case No. ER-2007-0004 that GMO, in the surrebuttal testimony of its witness Dennis R. Williams, included flow through of off-system sales margin in the FAC it requested. Staff could find nowhere in that case where a party argued for excluding off-system sales margin from flowing through GMO's FAC. For this additional reason, the Staff believes off-system sales revenues should flow through GMO's FAC and were intended by the Commission to be flowed through the FAC.

As stated above, the Staff is requesting the Commission clarify that off-system sales margin should flow through GMO's FAC since the FAC was first implemented for GMO. Off-system sales margins not included in the calculation of CAFs would be included in the true-ups of the recovery periods for the accumulation periods where the off-system sales margins were not included. If the Commission allows GMO to continue or modify its FAC, the Commission should explicitly state off-system sales margins flow through its FAC.

Staff also recommends that the Commission add another potential revenue stream to the FAC. Staff recommends that the Commission modify GMO's FAC to explicitly include any SO_2 allowance sales revenues since the cost of SO_2 purchases are allowed to flow through the FAC. If the cost of SO_2 allowance purchases are allowed but not the revenues from any sales, GMO has less incentive to manage its SO_2 allowances. Without including SO_2 sales, GMO could, because SO_2 purchases are flowed through the FAC, decide to sell SO_2 allowances to generate revenue for itself instead of saving its SO_2 allowances for later use.

In addition, Staff recommends that, when GMO begins participating in SPP's RTO,[16] GMO's SPP EIS market settlements and revenue neutrality uplift charges be included in the list of costs/revenues reflected in GMO's FAC since these are charges/revenues associated with balancing the resources with GMO's load.

[16] Effective February 10, 2009 The Commission approved GMO's participation in the Southwest Power Pool, Inc. (SPP) in Case No. EO-2009-0179.

Because GMO's fuel and purchased power costs for both MPS and L&P vary greatly between the summer (June through September) and the rest of the year (October through May), Staff recommends that GMO's FAC be modified to have a summer and winter bases instead of the current annual base.

The Staff will elaborate on these recommendations and present other, less significant proposed changes to GMO's FAC tariff sheets in Staff's Rate Design Report to be filed on February 27, 2009.

Staff Expert: Lena M. Mantle

XI. 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 two applicable jurisdictions: retail and wholesale operations. The application of a particular jurisdictional allocation factor is dependent upon the types of costs being allocated. These calculations were performed for GMO-MPS only. GMO-L&P has no electric wholesale customers; thus, these calculations were not necessary for that division.

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 energy requirement occurring within a specified period of time (e.g., hour, day, month, season, or 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 two individual jurisdiction, GMO-MPS retail and wholesale operations, coincident to these system peak demands is the appropriate basis on which to allocate the costs of these facilities. Thus, the term coincident peak refers to the load, generally in kiloWatts (kWhs) or megaWatts (MWs), in each of the jurisdictions that coincide with GMO-MPS'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 demand allocation factor for each jurisdiction was determined using the following process:

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

b. Sum the particular jurisdiction's corresponding loads for the hours identified in (a.) above.

c. Divide b. above by a. above.

The result is the allocation factor for each jurisdiction:

Retail Operations:	.9952
Wholesale Operations:	.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 GMO-MPS's total system kWh usage. Staff has calculated the following energy allocation factors for the particular jurisdictions:

Retail Operations:	.9949
Wholesale Operations:	.0051

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

Staff Expert: Alan J. Bax

B. Application

GMO MPS operates within two different jurisdictions, Missouri and the federal jurisdiction regulated by FERC. Therefore, it is necessary to specifically identify, allocate and/or assign utilities' investment and expenses between these 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 MPS for the generating facilities used to generate electricity and the transmission facilities used to transport electricity to MPS retail customers in Missouri and the FERC wholesale customers. This same infrastructure is used to generate and transport electricity to firm and non-firm customers in the bulk power markets (off-system sales).

MPS specifically identifies the distribution plant for the Missouri jurisdiction. This is referred to as site specific or situs plant and Staff used 100% allocation factors for distribution plant and reserve to identify the entire distribution plant as 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 for each functions. Each specific account had its own allocation factor that was used to allocate costs to Missouri and 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

XII. 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, in Case No EM-2007-0374, 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 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 recovery of costs incurred in combining the operations of KCPL and Aquila (transition costs). Transition costs are those costs incurred primarily post-closing of the merger to integrate the operations of the two companies. While it did support recovery of these transition costs, the Commission did not specify the method by which this recovery was to be accomplished.

Specifically, 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." Paragraph 14 further states 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 (2) methods by which a utility can recover acquisition or merger transition costs; direct rate recovery and indirect rate recovery. Using the direct rate recovery method a utility would defer the acquisition costs, file for a rate increase, and amortize the deferred costs as an increase to cost of service. The indirect rate recovery approach the utility would defer the merger or acquisition costs, amortize the costs to expense, but not seek direct rate recovery. Under this approach, the costs would be recovered through regulatory lag whereby the utility's increased revenues and/or decreased expenses would be sufficient to cover the increased costs of the specific event, thus still allowing the utility 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. These excess revenues collected in rates can be used to reduce or eliminate the cost of the merger or acquisition and the remaining excess rate recoveries will flow 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 in which acquisition savings are being realized, the acquisition savings flow through to customers as the reduced expenses of the new entity are reflected in current rates. In the interim between rate proceedings, the new entity is allowed to retain the total 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. It also benefits 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 was 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 the current 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 off the transition cost deferral and accrue as additional earnings 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. The same concept would apply to 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 was confirmed by William Downey, President and COO, Great Plains Energy and KCPL in an 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. 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. 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 (10) 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 request of Staff, KCPL provided an 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 essence, 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

XIII. Acquisition Detriment – Depreciation

As noted in the section on Depreciation, the Staff takes issue with MPS' accounting for certain ECORP assets that were retired as a result of its acquisition by Great Plains Energy. The Staff's position is that the accounting method and ratemaking proposal chosen by MPS results in an acquisition detriment as well as being inconsistent with the requirements of the FERC Uniform System of Accounts (USOA) for plant accounting. While the FERC USOA has no authority over the ratemaking decisions of the Commission, utility companies in Missouri are required to comply with the requirements of the USOA for bookkeeping purposes.

By removing the amount of the original cost of an asset that has not been fully depreciated from ECORP account 391.02 Computer Hardware and ECORP Account 391.04, Computer Software, Aquila has created a reserve deficiency or understatement of the associated reserve account balance as a result of the acquisition. Staff considers this a detriment of the acquisition and has made adjustments (R-155, R-156 MPS) to remove only the depreciated amount of this plant from the reserve. In addition, Staff believes that the USOA only allows the fully depreciated amount of the asset retired as a result of a merger or acquisition to be removed from the accumulated depreciation account for that asset. The Staff is aware that similar adjustments to the ones described above were made by MPS after the updated test year in this case and will update its position on this issue in its true-up recommendation to the Commission.

Staff Expert: Charles R. Hyneman

XIV. Service Quality

A. Post-Consolidation Service Quality of Aquila

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 below:

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
July	0.8	1.5	
August	1.3	1.5	7.8
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

Consolidation	
July 1-13	July 14-31
1.9	18.1

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		
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		

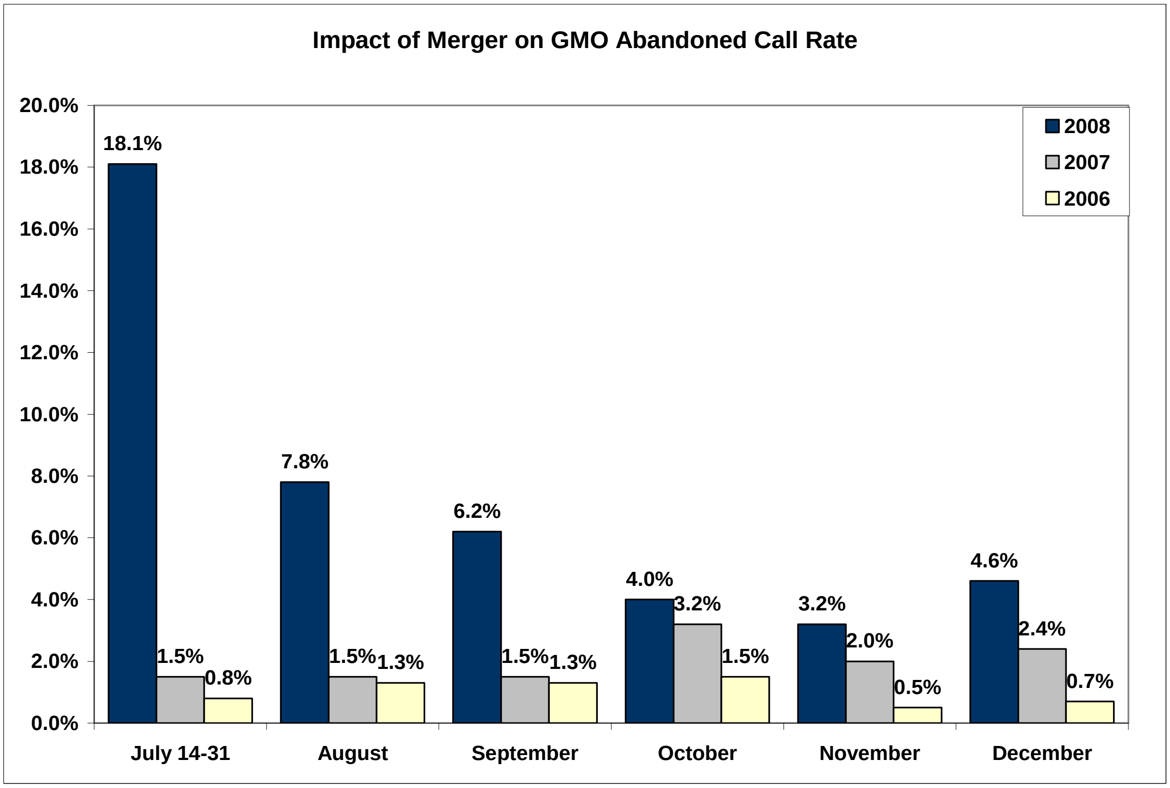
Source: GMO and KCPL Service Quality Reports provided to Staff and the Office of the Public Counsel as a result of Case Nos. EO-2005-0329 and ER-2004-0034.

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
July	45	40	
August	34	55	72
September	23	73	62
October	21	104	36
November	30	48	24
December	14	59	31

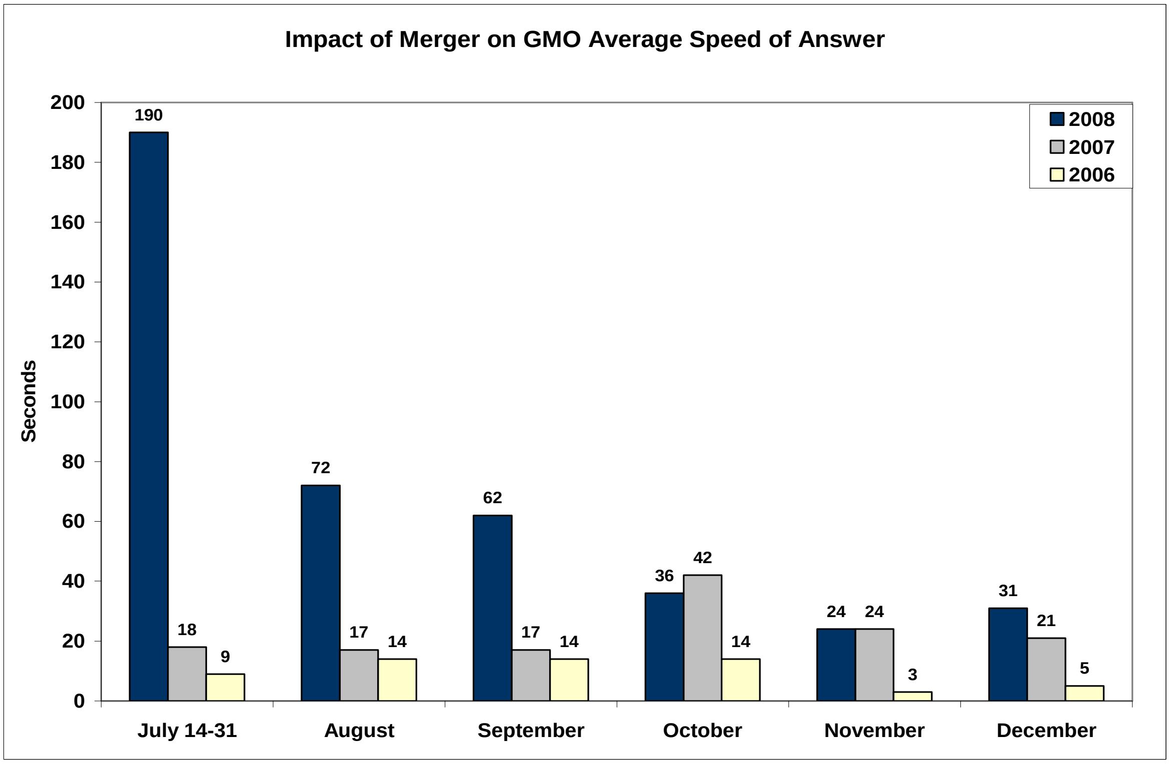
Consolidation	
July 1-13	July 14-31
58	190

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.

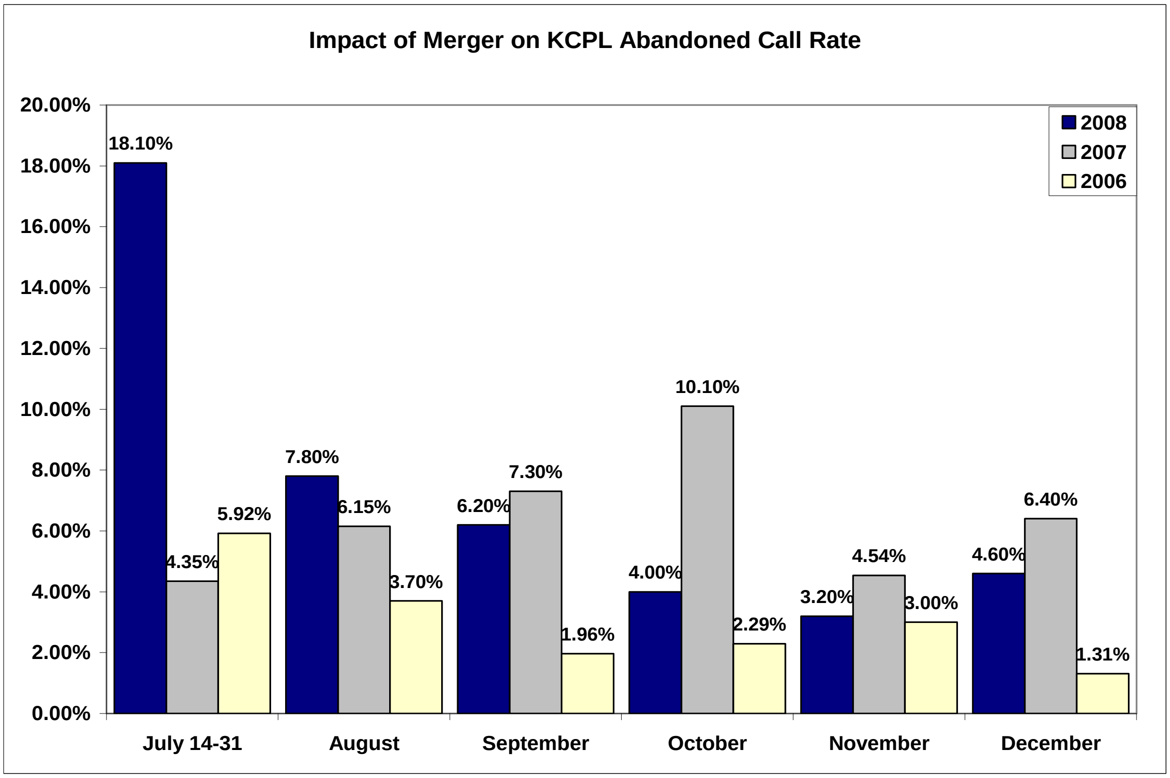
The following four graphs present the impact the merger has had on the ACR and ASA as compared to previous years for selected months for GMO and KCPL. With the exception of the July 2008 ASA, and KCPL's August 2008 ACR,, KCPL's call center performance metrics has improved over the previous year.



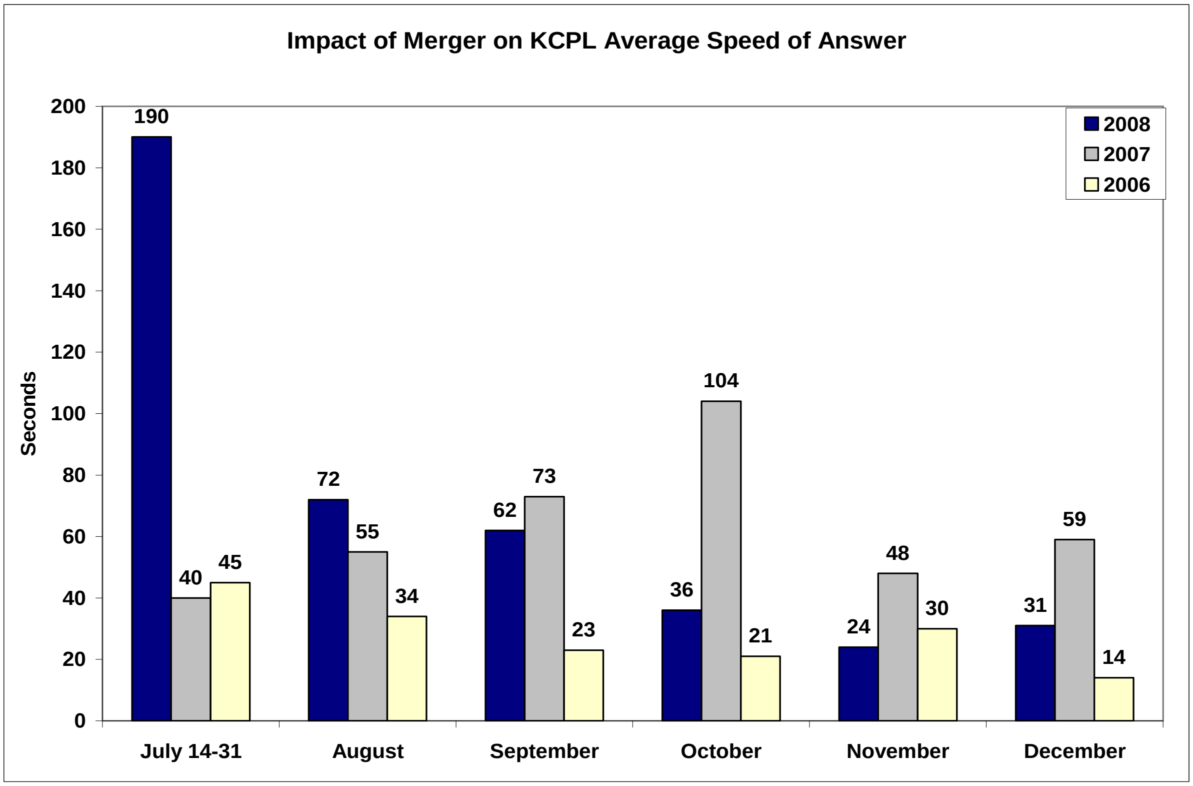
Source: GMO and KCPL Service Quality Reports provided to Staff and the Office of the Public Counsel as a result of Case Nos. EO-2005-0329 and ER-2004-0034.



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.

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

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

APPENDICES

Appendix 1: Staff Credentials

Appendix 2: David Murray Schedules and Attachments

Appendix 3: Walter Cecil Schedules

Appendix 4: Erin Maloney Schedule

Appendix 5: Lena Mantle Schedules

Appendix 6: Rosella Schad Schedules

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes in its Charges for Electric Service.	))))	Case No. ER-2009-0090

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 84-85 and 149-151; 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 13th 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 KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes in its Charges for Electric Service.	))))	Case No. ER-2009-0090

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 80-81 and 118-119 ; 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 13th day of February 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
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D Suzie Mankin

Notary Public

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OF THE STATE OF MISSOURI

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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 59-61, 66-67, 74-75 and 112-113 ; 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 13th day of February, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
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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 63-66; 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 13th 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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Notary Public

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AFFIDAVIT OF DAVID W. ELLIOTT

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

David W. Elliott, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 72-73 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.

David W. Elliott

Subscribed and sworn to before me this 13th day of February, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
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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 53-54, 57-58, 69-72 and 73-74; 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 13th day of February, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
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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 55-57, 98-102, 109-110, 116-117 and 140-142; 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 13th day of February, 2009.

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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 47-50, 106-108, 111-112, 115-116, 119-121 ; 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 13th day of February, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
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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 90-93, 102-103, 109, 118 and 153-162; 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.

Ch R. Hy

Charles R. Hyneman

Subscribed and sworn to before me this 13th day of February, 2009.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
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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 162 - 171; 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 13th 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 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 61 - 63 ; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Manisha Lakhanpal
Manisha Lakhanpal

Subscribed and sworn to before me this 13th 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

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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 82-84; 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 13th 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

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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 93 - 98 and 103-106; 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 13th 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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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 118; 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.

AL C McK

Adam C. McKinnie

Subscribed and sworn to before me this 13th 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 KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes in its Charges for Electric Service.	))))	Case No. ER-2009-0090

AFFIDAVIT OF ERIN L. MALONEY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Erin L. Maloney, of lawful age, on his oath states: that she has participated in the preparation of the foregoing Staff Report in pages 75-80; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Erin L. Maloney

Erin L. Maloney

Subscribed and sworn to before me this 13th 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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AFFIDAVIT OF LENA M. MANTLE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Lena M. Mantle, of lawful age, on his oath states: that she has participated in the preparation of the foregoing Staff Report in pages 85-90 and 142-149; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Lena M Mantle

Lena M. Mantle

Subscribed and sworn to before me this 13th 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

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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 8-47; 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

Subscribed and sworn to before me this 13th 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 KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes in its Charges for Electric Service.	))))	Case No. ER-2009-0090

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 51-52, 54-55, 113-114 and 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.

Bret G. Prenger

Bret G. Prenger

Subscribed and sworn to before me this 13th 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 KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes in its Charges for Electric Service.	))))	Case No. ER-2009-0090

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 122-139; 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 13th 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 KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes in its Charges for Electric Service.	))))	Case No. ER-2009-0090

AFFIDAVIT OF MICHAEL S. SCHEPERLE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Michael S. Scheperle, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 65-69; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Michael Scheperle
Michael S. Scheperle

Subscribed and sworn to before me this 13th 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