MISSOURI PUBLIC SERVICE COMMISSION

REVENUE REQUIREMENT

COST OF SERVICE REPORT

UNION ELECTRIC COMPANY
d/b/a AMERENUE

CASE NO. GR-2010-0363

Jefferson City, Missouri
November 8, 2010

TABLE OF CONTENTS OF

REVENUE REQUIREMENT

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I. EXECUTIVE SUMMARY

A. Staff's Revenue Requirement Recommendation

The Staff of the Missouri Public Service Commission ("Staff") has conducted a review and investigation of all cost of service components (capital structure and return on rate base, rate base, operating revenues and expenses) that comprise the revenue requirement of the Missouri gas operations of Union Electric Company d/b/a AmerenUE[1] ("AmerenUE" or "the Company"). This audit was in response to the Company's June 11, 2010 filing seeking to increase general retail (base) rates to charge its customer approximately $11.9 million additional annual revenue, based on a 10.5% return on equity. Staff's recommended revenue requirement for AmerenUE, based on estimated results through September 30, 2010, is approximately $ 6.9 million at Staff's recommended 8.60% mid-point rate of return on equity.

B. Impact of Staff's Revenue Requirement on Retail Rate Revenue

The impact of Staff's recommended revenue requirement on each of AmerenUE's rate classes will be discussed in Staff's rate design and class cost of service report, scheduled to be

[1] In a letter dated September 10, 2010, Union Electric Company notified the Commission that it had adopted the trade name "Ameren Missouri" and intended to use such name in communications with the Commission, customers, and stakeholders regarding its Missouri jurisdictional operations commencing October 1, 2010. For the sake of consistency and historical accuracy in reference to the test year employ in this case Staff has selected to refer to Union Electric's Missouri jurisdictional operations as "AmerenUE" and does not do so in an attempt to distinguish that entity from "Ameren Missouri".

filed on November 19, 2010. A portion of Staff's general rate increase recommendation is already being charged to AmerenUE's customers through the Infrastructure System Replacement Surcharge ("ISRS"). The Company is currently authorized by the Missouri Public Service Commission ("the Commission") to collect approximately $3.4 million annually in ISRS rates. When rates in this proceeding become effective, the Company's ISRS surcharge will be reset to zero. A mounts formerly collected through the ISRS surcharge will then be collected through AmerenUE's general retail (base) rates. When AmerenUE's ISRS charges are excluded, Staff's recommended incremental rate increase is approximately $3.5 million (Staff's revenue requirement recommendation in this case at mid-point of $6.9 million less $3.4 million of ISRS revenue).

II. BACKGROUND

The Missouri gas operations of AmerenUE provides service to approximately 126,500 customers in 25 counties throughout Eastern and Central Missouri. The Commission last authorized new rates for the Missouri gas operations of AmerenUE effective April 1, 2007. This prior rate proceeding was designated by the Commission as Case No. GR-2007-0003.

III. TEST YEAR AND TRUE-UP RECOMMENDATION

AmerenUE filed its rate increase request based on an historic test year ending December 31, 2009 and requested a true-up to include costs through November 30, 2010. As a result, AmerenUE's rate base and several income statement adjustments proposed by the Company reflected known or anticipated changes occurring up to eleven months beyond the end of the historic test year (i.e., through the end of November 2010). Examples of such Company-proposed post test year changes include plant additions, actual/expected wage increases and employee benefits cost changes.

In its July 13, 2010 *Staff Recommendation Regarding Test Year And True-up* Staff agreed with AmerenUE's December 31, 2009 test year, but proposed a shorter true-up period through September 30, 2010. On August 19, 2010, the Commission issued its *Order Adopting Joint Procedural Schedule and Procedural Requirements*. Among other things, the Commission in its order established a test year ending December 31, 2009, and a true-up period through September 30, 2010.

IV. MAJOR ISSUES

AmerenUE filed its case based upon a test year ending December 31, 2010. The Staff updated the major components of the Company's revenue requirement based on the last data available. The major known methodological or conceptual differences between the Staff and the Company as reflected in Direct Testimony filings include the following issues along with their approximate dollar value:

Rate of Return – Issue Value ($3.9 million) The Company's case reflects a 10.5% return on equity ("ROE"), while Staff is recommending an ROE range from 8.10% to 9.10%, with a 8.60% mid-point ROE.

Net Plant – Issue Value ($1.3 million) The Staff included the September 30, 2010 levels, while the Company used estimates of the expected levels through November 30, 2010.

Cash Working Capital – Issue Value ($500,000) This difference, is primarily the result of the Staff using different revenue and expense lags to calculate the cash working capital requirement.

Revenues - Issue Value <u>$2 million</u> Staff has eliminated all the interim ISRS revenues from its determination of revenue requirement. The Company however, has annualized the ISRS rates that were in effect during the test year.

Rate Case Expense - Issue Value ($900,000) Staff has disallowed a portion of the consulting and outside attorney fees proposed by AmerenUE. Staff has also spread the allowed cost over a three year period, which better reflects the historical frequency of the Company's gas rate case filings. The Company requested recovery of $1,000,000 in annual rate case expense.

Staff Expert/Witness: (Section I, II, III and IV) Stephen M. Rackers

V. RATE OF RETURN

A. Introduction

An essential ingredient of the cost-of-service ratemaking formula provided above is the rate of return ("ROR"), which is designed to provide a utility with a return of the costs required to secure debt and equity financing. This ROR is equal to the utility's weighted average cost of capital ("WACC"), which is calculated by multiplying each component ratio of the appropriate capital structure by its cost and then summing the results. While the proportion and cost of most components of the capital structure are a matter of record, the cost of common equity must be determined through expert analysis. Staff's expert financial analyst, Zephania Marevangepo, has determined AmerenUE's cost of common equity by applying a well-respected and widely-used methodology[2] to data derived from a carefully-assembled group of comparable companies. Staff then used that cost of common equity, together with other capital component information as of, test year date, December 31, 2010, to calculate AmerenUE's fair rate of return, as follows:

[2] Staff relied primarily on its Discounted Cash Flow ("DCF") analysis of a group of comparable utilities, checking the reasonableness of its result with a Capital Asset Pricing Model ("CAPM") analysis as well as by other corroborating data.

TABLE ONE: AMERENUE'S RATE OF RETURN:

Capital Component	Percentage of Capital	Embedded Cost	Weighted Cost of Capital Using Common Equity Return of: **8.10%**	**8.60%**	**9.10%**
Common Stock Equity	51.26%	-----	4.15%	4.41%	4.66%
Preferred Stock	1.48%	5.19%	0.08%	0.08%	0.08%
Long-Term Debt	47.26%	5.95%	2.81%	2.81%	2.81%
	100.00%		**7.04%**	**7.29%**	**7.55%**

See Schedule 16

As contained in Table One, Staff recommends, based upon its expert analysis, a return on common equity ("ROE") range of 8.10 percent - 9.10 percent and an overall ROR range of 7.04 percent - 7.55 percent, with point estimates of 8.6 percent and 7.3 percent respectively. The details of Staff's analysis and recommendations are presented in Appendix 2, Schedules 1-16, attached to this report.

B. Analytical Parameters

The determination of a fair rate of return is guided by principles of economic and financial theory; and by certain minimum constitutional standards. Investor-owned public utilities such as AmerenUE are private property that the state may not confiscate without appropriate compensation. The Constitution requires, therefore, that utility rates set by the government must allow a reasonable opportunity for the shareholders to earn a fair return on their investments. The United States Supreme Court has described the minimum characteristics of a Constitutionally-acceptable rate of return in two frequently-cited cases. In ***Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia,*** the Court stated:[3]

[3] 262 U.S. 679, 692-93, 43 S.Ct. 675, 679, 67 L.Ed. 1176, 1182-83 (1923).

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

Similarly, in the later of the two cases, ***Federal Power Commission v. Hope Natural Gas Co.,*** the Court stated:[4]

> '[R]egulation does not insure that the business shall produce net revenues.' But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view 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.

From these two decisions, Staff derives and applies the following principles to guide it in recommending a fair and reasonable ROR:

1. A return consistent with returns of investments of comparable risk;
2. A return sufficient to assure confidence in the utility's financial integrity; and
3. A return that allows the utility to attract capital.

[4] 320 U.S. 591, 603, 64 S.Ct. 281, 288, 88 L.Ed. 333, 345 (1943).

Embodied in these three principles is the economic theory of the opportunity cost of investment. The opportunity cost of investment is the return that investors forego in order to invest in similar risk investment opportunities, which will vary depending on market and business conditions.

The methodology of financial analysis has advanced greatly since the ***Bluefield*** and ***Hope*** decisions. Additionally, today's utilities compete for capital in a global market rather than a local market.[5] Nonetheless, the parameters defined in those cases are readily met using current methods and theory. The principle of the commensurate return is based on the concept of risk. Financial theory holds that the return an investor may expect is reflective of the degree of risk inherent in the investment, risk being a measure of the likelihood that an investment will not perform as expected by that investor. Any line of business carries with it its own peculiar risks and it follows, therefore, that the return AmerenUE's shareholders may expect is equal to that required for comparable-risk utility companies.

Financial theory holds that the company-specific DCF method satisfies the constitutional principles inherent in estimating a return consistent with those of companies of comparable risk;[6] however, Staff recognizes that there is also merit in analyzing a comparable group of companies as this approach allows for consideration of industry-wide data. Because Staff believes the cost of equity can be reliably estimated using a comparable group of companies and the Commission has expressed a preference for this approach, Staff relies primarily on its analysis of a comparable group of companies to estimate the cost of equity for AmerenUE.

[5] Neither the DCF nor the CAPM methods were in use when those decisions were issued.

[6] Because the DCF method uses stock prices to estimate the cost of equity, this theory not only compares the utility investment to other utilities, but it compares the utility investment to all available assets. Consequently, setting the allowed ROE based on a market-determined cost of equity is necessarily consistent with the principles of ***Hope*** and ***Bluefield***.

In this case, Staff has applied this comparable company approach through the use of both the DCF and the Capital Asset Pricing Model ("CAPM"). Properly used and applied in appropriate circumstances, both the DCF and the CAPM methodologies can provide accurate estimates of a utility's cost of equity. Because it is well-accepted economic theory that a company that earns its cost of capital will be able to attract capital and maintain its financial integrity, Staff believes that authorizing an *allowed* return on common equity based on the *cost* of common equity is consistent with the principles set forth in ***Hope*** and ***Bluefield***.

C. Current Economic and Capital Market Conditions

Determining whether a cost of capital estimate is fair and reasonable requires a good understanding of the current economic and capital market conditions, with the former having a significant impact on the latter. With this in mind, Staff emphasizes that an estimate of a utility's cost of equity should pass the "common sense" test when considering the broader current economic and capital market conditions.

1. Economic Conditions

The United States is presently emerging from the most severe recession since the Great Depression.[7] Although the economy is now again expanding, growth is projected to be low for the next couple of years.[8] As a result, economists generally expect the long-term Gross Domestic Product ("GDP") growth rate to be in the range of 4 to 5 percent, of which approximately 2.0 percent is attributed to inflation.[9]

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[7] Sara Murray, "Slump Over, Pain Persists: Bureau Calls End to Recession, Longest Since 1930s; Jobs Recovery Still Slow," *The Wall Street Journal*, September 21, 2010, pp. A1 and A2.

[8] Jon Hilsenrath and Luca Di Leo, "Fed Hints at Move to Boost Recovery," *The Wall Street Journal*, September 22, 2010, p. A2.

[9] The Congressional Budget Office (CBO), *The Budget and Economic Outlook: Fiscal Years 2010-2020,* August 2010; and The Energy Information Administration's *2010 Annual Energy Outlook*.

Because of the Federal Reserve Bank's ("Fed") concerns about the possibility of a double-dip recession and deflation, the Fed continues to maintain the Fed Funds Rate at historically low levels between 0.00 and 0.25 percent (*see* Schedules 2-1 and 2-2). Additionally, the Fed has pledged to embark on a bond buy-back program in order to provide continued liquidity to the financial system.

An example of investors' current low required real returns due to the current economic situation can be derived from the US Treasury's October 25, 2010 issuance of $10 billion of 5-year Treasury Inflation Protected Securities ("TIPS") at a yield of "-0.55" percent.[10] According to the article cited below, this is the first time TIPS have ever been sold at a *negative* real return. This negative real return implies that investors' return requirements are not related to growth, but to the possibility of an inflation offset to produce positive returns. If the inflation premium of 1.88 percent (1.33 percent 5-year Treasury rate less the negative 0.55 percent TIPS rate) is realized, then the TIPS investors will realize a total return equivalent to that of the 5-Year Treasury.

2. Capital Market Conditions

a. Utility Debt Markets

Utility debt markets clearly indicate a lower cost-of-capital environment. If one were to assume that the risk premium[11] required to invest in utility stocks rather than utility bonds were constant, then these lower utility debt yields clearly translate into a lower required return on equity. In other words, lower cost of debt is indicative of lower cost of capital, all else equal.

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[10] Mark Gongloff and Deborah Lynn Bluberg, "Yields on Tips Go Negative: Big Demand for Bonds Suggests Fed is Winning Deflation Battle; It 'Is Striking'" *The Wall Street Journal;* October 26, 2010, pp. C1 and C2.

[11] Risk Premium in this context is the excess required return to invest in a company's equity rather than its debt.

Unlike the short-term capital costs directly influenced by the Fed, long-term capital costs are market-based. Long-term interest rates, as measured by 30-year Treasury bonds ("T-bonds"), have decreased in recent months. The daily yield on 30-year T-bonds was 3.87 percent in October 2010, one of the lowest averages since April 2009 (*see* Schedules 4-2 and 4-3). Long-term utility bond yields have also declined in this cycle, contrary to what occurred in the last cycle, dropping to a 40-year low in October 2010 of 5.14 percent (*see* Schedules 4-1 and 4-3). As of October 2010, the average spread between 30-year T-bonds (3.87 percent) and average utility bond yields (5.14 percent)[12] was 127 basis points, which is 27 basis points below the average of such yields displayed in the period since 1980 (*see* Schedule 4-4). Recent utility bond yields have dropped to levels not experienced since the 1960s.[13]

While the cost of investment-grade utility debt capital has reached historic lows, the risk premium to invest in bonds of lower credit quality is higher than it was prior to the financial crisis of late 2008 and early 2009. Thus, while utilities with at least investment grade credit ratings can obtain capital quite cheaply, utilities with lower credit quality will pay a higher risk premium relative to risk-free rates than they did before the fall of 2008. However, the total required return on even borderline investment-grade debt is at levels not seen in at least 40 years.

The present low cost of utility capital is illustrated by the case of The Empire District Electric Company, which recently announced the issuance of $50 million of 30-year First Mortgage Bonds at a coupon of 5.20 percent, which will be used in part to redeem debt with

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[12] The 5.08 percent yields is based on an average from data obtained from BondsOnline.com For utility bond yields Staff provides prior to September 2010, Staff used Mergent Bond Record. Staff has canceled its subscription to Mergent Bond Record and will rely on data it receives from BondsOnline pursuant to a subscription agreement.

[13] Because Staff does not have utility bond yield data dating back to the 1960s, this is based on Staff's review of general corporate bond yields that were available from the St. Louis Federal Reserve website. This data showed that the general level of bond yields was much lower in the 1960s.

a coupon of 7.05 percent maturing in 2022. Additionally, Empire was able to issue 10-year First Mortgage Bonds at the favorable rate of 4.65 percent last May, despite its lower Standard & Poors ("S&P") corporate credit rating of "BBB-."

b. Utility Equity Markets

Investors view regulated utility company stock investments as a close alternative to bond investments. Therefore, similar to bond investments, typically when long-term interest rates fall, regulated utility company stock prices increase. Assuming there is no change in the fundamentals of the industry, this translates directly into a lower cost of equity for regulated utility companies.

Therefore, the current low levels of long-term interest rates on 30-year T-bonds and public utility bonds support Staff's opinion that the cost of equity to regulated gas utility companies is currently lower.

D. AmerenUE's Operations

The following excerpt from Ameren Corporation's Form 10-K filing with the SEC for the 2010 calendar year provides a good description of AmerenUE's current business operations:

> Union Electric unites electricity and natural gas services under the Gateway Arch. The utility (a subsidiary of Ameren) operates as Ameren Missouri and serves 1.2 million power customers and more than 127,000 gas customers. The utility's service territory includes 57 Missouri counties; more than half of its customers reside in the St. Louis metropolitan area. The company owns about 3,300 miles of natural gas transmission and distribution mains and 33,000 of electric distribution lines. AmerenUE owns or has interests in nine power plants (primarily thermal) with a capacity of almost 10,000 MW, and it also engages in wholesale power transactions.
>
> All of UE's natural gas operating revenues were subject to regulation by the MoPSC in the year ended December 31, 2009. If certain criteria are met, UE's natural gas rates may be adjusted

> without a traditional rate proceeding. PGA clauses permit prudently incurred natural gas costs to be passed directly to the consumer. The ISRS also permits prudently incurred natural gas infrastructure replacement costs to be passed directly to the consumer.

On October 1, 2010 AmerenUE changed its name to Ameren Missouri; and the three Ameren Illinois utilities (CILCO, CIPS and IP) were merged to form a second subsidiary – Ameren Illinois Company. Ameren Corporation affirmed that the change will help to minimize customer confusion as each subsidiary will be identified by its service territory. Otherwise, the provision of services will not be impacted and no advertising costs will be incurred to promote the change.[14]

E. AmerenUE's Credit Ratings

AmerenUE is currently rated by Moody's, S&P and Fitch Ratings ("Fitch"). AmerenUE's issuer/ corporate credit ratings are 'Baa2', 'BBB-' and 'BBB+' respectively. While all three ratings are classified as "lower medium" grade, S&P's rating is only one notch above "junk" status, i.e. non-investment grade. Unlike other rating agencies, S&P's AmerenUE credit rating is a mere reflection of Ameren Corporation's consolidated credit profile.

The three credit rating agencies, Moody's, S&P and Fitch, rate AmerenUE's secured debt as 'A3', 'BBB' and 'A'. Moody's and Fitch credit ratings are both classified as "upper medium" grade while S&P is "lower medium" grade.

A key difference in the rating methodologies between S&P and the other two agencies (Moody's and Fitch) is in the amount of weight that each agency gives to the stand-alone subsidiary business and financial risks in assigning ratings. S&P tends to rate most companies based on the consolidated risk profile of the parent company, whereas Moody's and Fitch tend to

[14] http://www.ameren.com/sites/aue/Documents/AmerenMissouriCustomerLetter.pdf

give at least some weight to the stand-alone subsidiary risk profile in rating the subsidiary's credit risk.

Since S&P rates AmerenUE based on Ameren's consolidated credit profile, other regulated and non-regulated subsidiaries' higher financial and business risks have a direct impact on the issuer and secured debt rating assigned to AmerenUE by S&P.

F. Cost of Capital

In order to arrive at Staff's recommended ROR, Staff specifically examined (1) appropriate ratemaking capital structure, (2) the embedded cost of debt, (3) the embedded cost of preferred stock, and finally, (4) the Company's cost of common equity.

1. Capital Structure

Schedule 5 presents AmerenUE's and Ameren's historical capital structures in dollar terms and percentage terms for the past five years. As can be derived from these historical capital structures, the current capital structure of AmerenUE is fairly consistent with the way in which Ameren has been capitalized over this period, easing any concerns Staff may have regarding manipulation of AmerenUE's capital structure for ratemaking purposes.

Consequently, Staff accepted the AmerenUE capital structure provided in the direct testimony of Michael G. O'Bryan (*see* Schedule MGO-G1). The capital structure is as of the end of the test year period ending December 31, 2009. Schedule 6 presents AmerenUE's capital structure and associated capital ratios. The resulting capital structure consists of 51.26 percent common stock equity, 1.48 percent preferred stock and 47.26 percent long-term debt.

2. Embedded Cost of Debt and Preferred Stock

Staff also accepted the embedded cost of long-term debt and preferred stock provided in the direct testimony of Michael G. O'Bryan (*see* Schedule MGO-G2 and Schedule MGO-G4). This approach is consistent with Staff's position in prior AmerenUE electric rate cases.

3. Cost of Common Equity

Staff's expert financial analyst, Zephania Marevangepo, determined AmerenUE's cost of common equity through a comparable company cost-of-equity analysis of a proxy group of seven companies using the Discounted Cash Flow ("DCF") methodology. Additionally, Staff used a CAPM analysis and a survey of other indicators as a check of the reasonableness of its recommendations.

a. The Proxy Group

First, Staff formed a group of comparable companies for the commensurate return analysis. Starting with 11 market-traded natural gas utilities (*see* Schedule 7), Staff applied a number of criteria to develop a proxy group comparable in risk to AmerenUE's regulated natural gas distribution operations (*see* Schedule 8):

1. Stock publicly traded (0 companies eliminated, 11 remaining);
2. Information printed in Value Line (0 companies eliminated, 11 remaining);
3. Ten years of data available (0 companies eliminated, 11 remaining);
4. At least investment grade credit rating (0 companies eliminated, 11 remaining);
5. Two sources for projected growth available with one of those being from Value Line (1 company eliminated, 10 remaining); and
6. No reduced dividend since 2007 (3 companies eliminated, 7 remaining).

This final group of seven publicly-traded natural gas utility companies ("the comparables") was used as a proxy group to estimate the cost of common equity for AmerenUE natural gas utility operations. The comparables are listed on Schedule 8.

b. The Constant-growth DCF

Next, Staff calculated AmerenUE's cost of common equity applying values derived from the proxy group to the constant-growth DCF model. The constant-growth DCF model is widely used by investors to evaluate stable-growth investment opportunities, such as regulated utility companies. The constant-growth version of the model is usually considered appropriate for mature industries such as the regulated utility industry.[15,16] It may be expressed algebraically as follows:

$$k = D_1/P_0 + g$$

Where: k is the cost of equity;

D_1 is the expected next 12 months dividend;

P_S is the current price of the stock; and

g is the dividend growth rate.

The term D_1/P_0, the expected next 12 months dividend divided by current share price, is the dividend yield. Staff calculated the dividend yield for each of the comparable companies by dividing the weighted average of the 2010 (25 percent) and 2011 (75 percent) Value Line projected dividends per share (*see* Schedule 13) by the monthly high/low average stock price for

[15] Aswath Damodaran, *Investment Valuation: Tools and techniques for determining the value of any asset,* University Edition, John Wiley & Sons, Inc., 1996, p. 195-196.

[16] 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.

the three months ending September 30, 2010 (*see* Schedule 13).[17] Staff weighted the Value Line projections in this manner in order to reflect the approximate amount of time remaining in 2010. Staff uses the above-described stock price because it reflects the most current market value of stocks. The projected average dividend yield for the seven comparable companies is 4.10 percent, unadjusted for quarterly compounding.

c. The Inputs

In the DCF method, the cost of equity is the sum of the dividend yield and a growth rate ("g") that represents the projected capital appreciation of the stock. In estimating a growth rate, Staff considered both the actual dividends per share ("DPS"), earnings per share ("EPS") and book value per share ("BVPS") for each of the comparable companies and also the projected DPS, EPS and BVPS. In reviewing actual growth rates, Staff found the historical growth rates to be unsustainable in perpetuity. Additionally, the growth rates were greater than the current long-term GDP projections of approximately 4 – 5 percent.[18] Staff then analyzed the projected DPS, EPS and BVPS estimated by Value Line for each of the comparable companies over the next five years (*see* Schedule 11). The average for seven comparables was 4.71 percent. Equity analysts' 5-year EPS estimates on *Reuters.com* also showed an average growth rate of 4.89 percent (*see* Schedule 11, Column 3).

Due to the Staff's concerns about the sustainability of historical DPS, EPS, and BVPS growth rates, Staff does not believe significant weight should be afforded these growth rates in

[17] The monthly high/low averaging technique minimizes the effects of short-term stock market volatility on the calculation of dividend yield. P0 is calculated by averaging the highest and the lowest price for each month during the selected period.

[18] Schedule 9-1 depicts the annual compound growth rates for DPS, EPS and BVPS for each comparable company for the past ten years. Schedule 9-2 lists the annual compound growth rates for DPS, EPS and BVPS for each of the comparable companies for the past five years. Schedule 9-3 shows the averages of the growth rates shown in Schedules 9-1 and 9-2.

estimating the cost of equity using the constant-growth DCF. However, the range of projected DPS, EPS and BVPS (3.57 – 4.71 percent) and the average appears to be more consistent with expected economic conditions going forward. Staff's used an estimated constant-growth rate range of 4.0 percent to 5.0 percent for its constant-growth DCF cost of equity estimate. Although this is consistent with projected economic forecasts and some projected growth rates, Staff notes the historically, natural gas companies' long-term average EPS, DPS and BVPS growth rates have been less than that of the overall economy.

Using the constant-growth DCF model and the inputs described above -- a projected dividend yield of 4.10 percent and a growth rate range of 4.0 percent to 5.0 percent -- Staff has calculated AmerenUE's cost of common equity at 8.10 percent to 9.10 percent (*see* Schedule 16).

G. Tests of Reasonableness

Staff has tested the reasonableness of its DCF results, both by use of a CAPM analysis and by consideration of other evidence.

1. The Capital Asset Pricing Model

The CAPM is built on the premise that the variance in returns is the appropriate measure of risk, but only the non-diversifiable variance (systematic risk) is rewarded. Systematic risks, also called market risks, are unanticipated events that affect almost all assets to some degree because the effects are economy wide. Systematic risk in an asset, relative to the average, is measured by the Beta of that asset. Unsystematic risks, also called asset-specific risks, are unanticipated events that affect single assets or small groups of assets. Because unsystematic risks can be freely eliminated by diversification, the reward for bearing risk depends on the level of systematic risk. The CAPM shows that the expected return for a particular asset depends on the pure time value of money (measured by the risk free rate), the reward for bearing systematic risk (measured by the market risk premium), and the amount of systematic risk (measured by Beta). The general form of the CAPM is as follows:

$$k = Rf + \beta \, (Rm - Rf)$$

Where:	k	is the expected return on equity for a security;
	Rf	is the risk-free rate;
	β	is beta; and
	Rm - Rf	is the market risk premium.

For inputs, Staff relied on historical capital market return information through the end of 2009. For the risk-free rate ("Rf"), Staff used the average yield on 30-year U.S. Treasury bonds for the three-month period ending September 30, 2010; that figure was 3.85 percent. For Beta, Staff used Value Line's betas for the comparable companies (*see* Schedule 14). The average beta ("β") for the proxy group was 0.65. For the market risk premium ("Rm – Rf"), Staff relied on risk premium estimates based on historical differences between earned returns on stocks and earned returns on bonds.[19] The first risk premium was based on the long-term, arithmetic average of historical return differences from 1926 to 2009, which was 6.00 percent. The second risk premium was based on the long-term, geometric average of historical return differences from 1926 to 2009, which was 4.40 percent.

Staff's CAPM is presented on Schedule 14. The results using the long-term arithmetic average risk premium and the long-term geometric risk premium are 7.71 percent and 6.66 percent, respectively. These low cost of common equity results support the reasonableness of Staff's higher cost of equity estimates derived from its DCF analysis. Staff again notes that both U.S. Treasury yields and utility bond yields are quite low (at levels last experienced in the

[19] From Ibbotson Associates, Inc.'s *Stocks, Bonds, Bills, and Inflation: 2010 Yearbook.*

early 1960s) and the spread between them is presently below their long-term average. It is not improbable that investors are only requiring returns on common equity in the 7 to 8 percent range for utility stocks.

2. Other Tests

a. The "Rule of Thumb"

A "rule of thumb" method allows estimation of the cost of equity by adding a risk premium to the yield-to-maturity ("YTM") of the subject company's long-term debt. Based on experience in the U.S. markets the typical risk premium is in the 3 to 4 percent range.[20] Considering this is based on general U.S. capital market experience and regulated utilities are on the low end of the risk spectrum of the general U.S. market, a risk premium closer to 3 percent seems logical. This is especially true considering that regulated utility stocks behave like bonds. For the months of July, August and September 2010, "A" rated 30-year utility bonds and "Baa" rated 30-year utility bonds had average yields of 5.14 percent and 5.71 percent respectively.[21] Adding a 3 percent risk premium, the "rule of thumb" predicts a cost of common equity between 8.14 percent and 8.71 percent. Adding a 4 percent risk premium, the "rule of thumb" predicts a cost of common equity between 9.14 percent and 9.71 percent.

b. Average Authorized Returns

In the past, the Commission has applied a test of reasonableness using the average authorized returns published by Regulatory Research Associates ("RRA") as a benchmark. According to RRA, the average authorized cost of common equity for natural gas utility companies for the first three quarters of 2010 was 10.07 percent based on twenty-four decisions

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[20] 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. 54.

[21] BondsOnline.com pursuant to a subscription agreement Staff has with BondsOnline.

(first quarter – 10.24 percent based on nine decisions; second quarter – 9.99 percent based on eleven decisions; third quarter – 9.93 percent based on four decisions). The average authorized cost of common equity for natural gas utility companies for 2009 was 10.19 percent based on twenty-nine decisions (first quarter – 10.24 percent based on four decisions; second quarter – 10.11 percent based on eight decisions; third quarter – 9.88 percent based on two decisions; fourth quarter – 10.27 percent based on fifteen decisions).

The average authorized ROR for natural gas utilities for the first three quarters of 2010 was 8.01 percent based on twenty-five decisions (first quarter – 8.20 percent based on ten decisions; second quarter – 7.80 percent based on eleven decisions; third quarter – 8.13 based on four decisions). The average authorized ROR for natural gas utilities in 2009 was 8.15 percent based on twenty-eight decisions (first quarter – 8.11 percent based on five decisions; second quarter – 8.05 percent based on seven decisions; third quarter – 8.30 percent based on two decisions; fourth quarter – 8.19 percent based on fourteen decisions).

While Staff understands the Commission's desire to review other commissions' authorized ROE's due to concerns about Missouri-jurisdictional utilities having to compete with other utilities for capital, Staff would like to briefly explain why an allowed ROE is not indicative of a required ROE and the ability to attract capital. The primary consideration for attraction of capital is whether the current price of a given stock will result in the investor earning above, below or equivalent to their required return. For example, the allowed ROEs for many of Southern Companies' utility subsidiaries are typically much higher than the rest of the utilities in the country. However, this does not translate into higher realized returns for investors in Southern Company because the price of Southern Company's stock already reflects these high allowed ROEs. This is very premise of the efficient market hypothesis. If this Commission were to award an ROE similar to those allowed for Southern Company's subsidiaries and hold all other ratemaking treatments constant, then current investors in the Missouri utility would achieve a return that was higher than their required return. However, after the increase in the Missouri utility's stock price, the investor and subsequent prospective investors would revert back to earning their required return. The opposite holds true if the Commission were to authorize an ROE below what is expected from the Commission. Consequently, setting allowed ROEs based on those allowed or earned for other companies may temporarily cause upward or downward pressure on the stock, but once this price correction occurs, the stock should experience "normal" capital attraction.

H. Conclusion

A just and reasonable rate is one that is fair to the investors and fair to the ratepayers. Fairness to the ratepayers means rates that are not one penny more than is necessary to be fair to the shareholders. Fairness to the shareholders means rates that will produce revenues, on an annual basis, sufficient to cover AmerenUE's prudent cost of service, which includes its cost of capital. Using widely-accepted methods of financial analysis, Staff has developed a weighted average cost of capital for AmerenUE in the range of 7.04 percent to 7.55 percent (*see* Schedule 16). This rate was calculated by applying an embedded cost of long-term debt of 5.95 percent and a cost of common equity range of 8.10 percent to 9.10 percent to a capital structure consisting of 51.26 percent common equity, 47.26 percent long-term debt and 1.48 percent preferred stock. Staff urges the Commission to accept its recommendation and allow AmerenUE to earn a fair return on its net rate base of 7.04 percent to 7.55 percent.

Staff Expert/Witness: Zephania Marevangepo

VI. DEVELOPMENT OF ACCOUNTING SCHEDULES AND ADJUSTMENTS

A. Revenue Requirement - Accounting Schedule 1

Staff's recommended overall base rate increase, reflecting the rate of return range discussed in Section V of this Report is summarized on Accounting Schedule 1. The various components included in this Schedule are further detailed in other supporting schedules, which are discussed later in this Report. As Schedule 1 shows, Staff is recommending a revenue requirement range of $5,998,969 to $ 7,871,184.

Staff Expert/Witness: Stephen M. Rackers

B. Rate Base - Accounting Schedule 2

Accounting Schedule 2 reflects the Company's rate base by major component. Rate base is the level of investment on which AmerenUE is allowed to earn a return. The components of Plant in Service, Accumulated Depreciation Reserve and Cash Working Capital are further detailed in other supporting schedules and are further discussed below. For the components of Gas Stored Underground, Materials and Supplies, Propane, Prepayments, Customer Deposits and Customer Advances Staff has used 13 month average balances ending either December 31, 2009 or September 30, 2010. The use of an average balance reflects the fact that these components fluctuate throughout the year. The components for Accumulated Deferred Income Taxes, Pension Tracker and OPEB Tracker are accumulated balances, and therefore reflect a point-in-time balance. Since the Commission ordered cut-off date for the true-up is September 30, 2010, Staff has included either estimated balances through September 30, 2010 or balances reflecting the latest data available for these components. These balances will be trued up when actual data becomes available. The offsets for Federal, State and City Tax and

Interest Expense reflect the cash working capital associated with these items. These components will be further discussed as part of explanation of the Cash Working Capital schedule.

Staff Expert/Witness: Stephen M. Rackers

C. Plant In Service – Accounting Schedule 3

Accounting Schedule 3 reflects AmerenUE's Plant in service balances directly assigned or allocated to the Company's gas operations. The plant balances have been adjusted to reflect the actual level at the end of the true-up period, September 30, 2010. The adjustments to the December 31, 2009 plant balances reflecting the changes through September 30, 2010 appear in the Adjustments to Plant in Service – Accounting Schedule 4.

Staff Expert/Witness: Lisa M. Ferguson

D. Depreciation Expense – Accounting Schedule 5

Accounting Schedule 5 reflects the computation of annualized depreciation expense, based on the balances that appear in Plant - Accounting Schedule 3, and the depreciation rates proposed by Staff witness David Williams and discussed in Section VII of this report. The depreciation expense calculated in Accounting Schedule 5 is used to determine the level of depreciation expense reflected in the Income Statement - Accounting Schedule 9.

Staff Expert/Witness: Lisa M. Ferguson

E. Accumulated Depreciation Reserve – Accounting Schedule 6

Accounting Schedule 6 reflects AmerenUE's Accumulated Depreciation Reserve balances directly assigned or allocated to the Company's gas operations. The reserve balances have been adjusted to reflect the level at the end of the true-up period, September 30, 2010. The adjustments to the December 31, 2009 reserve balances reflecting the changes to the reserve through September 30, 2010 appear in the Adjustments for Depreciation Reserve – Accounting Schedule 7.

Staff Expert/Witness: Lisa M. Ferguson

F. Cash Working Capital – Accounting Schedule 8

1. Use of lead/lag study

Cash working capital is defined as the amount of cash necessary for a utility to pay its day to day expenses that are incurred in providing service to its ratepayers. Cash working capital can also be roughly defined as a measurement of the timing of a utility's cash flows inward from customers and outward to vendors, employees, taxing authorities, etc. In order to study the timing of these cash flows, and more importantly the effect of the timing, Staff conducted what is referred to as a lead/lag study. A comparison of a utility's revenue lag with its expense lag indicates whether the Company receives the funds from customers to pay its day to day expenses before or after payment is due to vendors. A revenue lag is the amount of time from when the Company provides service to a customer and when the Company receives payment from the customer. An expense lead/lag is the amount of time from when a vendor provides a service to the Company and when the Company pays that vendor. If the Company pays for the service before the service is performed then that is called an expense lead. If the Company pays for the service after the service is performed then that is called an expense lag. In certain instances, after examining the appropriateness of AmerenUE's CWC calculations, Staff used the same revenue and expense lag factors as those recommended by the Company. In other situations, Staff determined that the lag AmerenUE calculated was not appropriate. If Staff determined a new lag was more appropriate, Staff developed a new lag based on different or updated information from the current case.

2. Revenue Lag

The revenue lag, discussed above, is composed of a service lag, a billing lag and a collection lag. A service lag is the midpoint of the period of time elapsed from the beginning of the first day of a service period (the meter reading day) to the end of the last day of a service period (the next meter read date). The billing lag is the period of time incurred between the end of the last day of a service period and the date the bill is placed in the mail by the Company. The collection lag is the period of time incurred between the day a bill is placed in the mail by the Company and the day the Company collects payment from the ratepayer for services rendered. Staff has accepted AmerenUE's calculation of the service and billing lags, but is using a different collection lag than the one provided by the Company.

The Company developed its revenue collection lag using accounts receivable aging reports. An aging report segments the accounts receivable balance based on the number of days the dollars have been outstanding. However, Staff used the "CURST 246 Report", which calculates the actual period of time the customers take to pay their bills. This report has been used by both Staff and the Company to determine the revenue collection lag in previous rate cases. In Staff's opinion the CURST 246 Report, if used appropriately, accurately measures the amount of time it takes customers to pay their bills. To the contrary, the aging reports include customer accounts that will eventually end up as bad debts. Staff believes the revenue lag should reflect the habits of paying customers. In addition the Company has been provided a specific expense amount in the cost of service that reflects bad debts associated with non paying customers.

The Company has modified the calculation of the collection lag it used in prior rate cases to adjust the aging report data to reflect accounts that will never be paid and will ultimately end up as bad debts. However, the Company has not provided Staff with any support for how these bad debt adjustments were determined. In response to Data Request No. 117, Company witness Adams conveyed that "no supporting documentation was relied upon pertaining to the uncollectibles percentages for purposes of preparing the lead-lag study or the Collection Lag". As a result, Staff is unable to make any determination regarding the validity of AmerenUE's aging report adjustment.

In addition, AmerenUE has also included a component to its calculation of the revenue lag for payment processing. Payment processing is the time period from when the Company receives payment and when that payment is deposited by the Company. Staff has traditionally not recognized processing lags as components of the calculation of either the revenue or expense lags and does not believe the Company has provided sufficient support for including this item in this case. As a result of its calculations and review and acceptance of some of AmerenUE's determinations, Staff recommends a service lag of 15.21 days, a billing lag of 0.96 days and a collection lag of 20.18 days, for a total revenue lag of 36.35 days.

In the case of pass-through taxes such as gross receipts tax, Staff is only using the collection lag portion of the total revenue lag, 20.18 days. The utility company acts as a conduit to collect city franchise taxes and sales taxes from its customers and remits these payments to the appropriate governmental entities. Therefore, no service is provided to customers with regard to these pass-through taxes other than the collection process, and only the collection lag portion of the revenue lag is appropriate for these expenses.

3. Expense Lags

After reviewing AmerenUE's calculations, Staff has accepted a majority of the Company's expense lags. The major differences exist with regard to the lags for employee benefits and gross receipts taxes. The first difference is in employee benefits, where Staff used the Company's lag calculations for the individual components of health and life insurance, pensions, 401k and other post-retirement employee benefits ("OPEBs"). However, in AmerenUE's calculation of the overall employee benefits lag, it weighted the components by the associated dollars it analyzed in its lead/lag study, which was not consistent with the expense value of the individual components. Therefore, Staff weighted the lags for each of the components by the associated annualized expense amounts to determine the overall employee benefits expense lag.

The second main difference can be found in the gross tax receipts expense lag. AmerenUE did not consider the fact that individual communities require different schedules for remittance of the tax collections when calculating the expense lag for gross receipts taxes. For example, while AmerenUE collects gross receipts tax monthly from customers, it is only required to make semi-annual remittance of the tax to the City of Cape Girardeau, and for the City of Booneville remittance is required monthly. Staff properly recognized these different remittance requirements in its calculations, resulting in a gross receipts tax expense lag of 58.16 days, as opposed to the 27.66 days determined by AmerenUE. In addition, Staff included a separate line item in its CWC schedule for the St. Louis Payroll Expense Tax, which was not specifically identified in AmerenUE's analysis. Including this item in Staff's analysis reduced the cash working capital requirement.

Staff Expert/Witness: Lisa M. Ferguson

G. Income Statement Detail – Accounting Schedule 9

In order to calculate AmerenUE's Missouri gas retail base rate revenue requirement, it is necessary to determine the net income (revenues minus expenses) that is available, based on annualized and normalized Missouri gas operations. The Staff's calculation of the net income available appears on the Income Statement Detail – Accounting Schedule 9. The retail sales revenues on this schedule are determined based on annualized customer counts and normalized usage, priced at existing retail base rates. All operation and maintenance expenses, income tax and other tax expenses, as well as depreciation expense are annualized and normalized to reflect the appropriate on-going levels. The adjustments to revenues and expenses are detailed on the Adjustments to Income Statement Detail – Accounting Schedule 10. On the Revenue Requirement - Accounting Schedule 1, the net income from the Income Statement is subtracted from the net income determined by multiplying the rate base by the rate of return. The result of this calculation, factored-up for income taxes, is the revenue requirement recommended by the Staff.

Staff Expert/Witness: Stephen M. Rackers

1. Revenues

Staff calculated annualized revenues, utilizing estimated customer counts at September 30, 2010, normalized usage per customer and existing base tariff rates. Staff did not calculate the annualized impact of the ISRS that was in effect during the test year, nor did it calculate the annualized impact of the ISRS tariff change that became effective during 2010, when arriving at revenues *at existing permanent/base rates.* The ISRS currently in effect, customers are paying approximately $3.4 million in additional annual revenues above amounts being collected through base rates. When base rates are designed in this proceeding, the ISRS rate will be rolled into base rates and the ISRS will be reset to “zero” (generally referred to as “rebasing”).

Staff Expert/Witness: Stephen M. Rackers

a. Adjustment for Unbilled Revenues

Staff eliminated unbilled revenue from its determination of revenue requirement. The recording of unbilled revenue on the books of the Company is an attempt to recognize sales of gas that have occurred, but that have not been billed to the customers. Since Staff has adjusted revenues to assure that it includes only 365 days of revenue, and since the revenues have been restated to a billed basis, it is necessary to remove unbilled revenue in order to reach an accurate revenue requirement.

Staff Expert/Witness: Kofi Agyenim Boateng

b. Adjustment to Remove Gas Costs

All revenue adjustments in Staff's cost of service calculation were priced on the margin rate (the total rate excluding gas cost) included in the Company's tariffs. Therefore, revenues and expenses related to gas costs were removed from Staff's revenue requirement calculation. The cost of gas will be addressed as part of Staff's review of the Company's Purchase Gas Adjustment ("PGA") and Actual Cost Adjustment ("ACA") filings, conducted in subsequent proceedings.

Staff Expert/Witness: Kofi Agyenim Boateng

c. Adjustment to Remove Gross Receipts Taxes ("GRT")

The Company acts as a collector for taxes imposed on utility service revenues by municipalities and other taxing jurisdictions. The GRT included on a customer's bill is collected by the Company and remitted to the appropriate taxing jurisdiction. The GRT included on a customer's bill is recorded as revenue on the books of the Company, with a corresponding charge booked to GRT expense. Theoretically, the revenue and expense offset one another and, therefore, have no effect on net income. However, the expense accrual for GRT does not always match perfectly with the GRT included in revenue due to timing differences in the collection and payment of the GRT. Eliminating the GRT recorded in revenue and expense through companion adjustments assures that GRT will have no impact on the calculation of net income or revenue requirement.

Staff Expert/Witness: Kofi Agyenim Boateng

d. Adjustment to Remove ISRS Amounts

During the test year, the Company collected through the ISRS mechanism certain revenues received as a result of the surcharge approved by the Commission in Case Nos. GT-2009-0413 and GO-2010-0257. The ISRS mechanism is designed to recover the costs associated with the Company's eligible infrastructure replacements in accordance with the provisions of Sections 393.1009 to 393.1015, RSMo (2000). These revenues must be removed from the test year in order to reflect the current on-going level of permanent base rate revenues. These surcharges will expire, in other words, will be reset to zero and included in base rates at the time new rates are established by the Commission in this rate proceeding.

Staff Expert/Witness: Kofi Agyenim Boateng

e. Customer Growth Annualization

For customer classes that exhibited a trend in customer growth or decline levels, Staff made adjustments to the test year to reflect the addition or reduction in rate revenue that would have occurred if the number of customers taking service at the end of the update period (September 30, 2010), had existed throughout the entire test year. For customer classes that exhibited seasonality in customer levels, Staff also made adjustments to reflect the current ongoing level of customers. Customer growth was calculated for the residential, small general service, and large general service customer classes. The customer annualization adjustments for both trend and seasonality take into account weather and usage normalizations, as well as the adjustments for 365 days and permanent rate changes that occurred during the test year, if any.

Staff Expert/Witness: Kofi Agyenim Boateng

f. Weather Normal Variables Used for Weather Normalization - Regulatory Adjustments to Test year Sales and Rate Revenue

Natural gas usage and revenues vary from year to year based on weather conditions. Since each year's weather is unique, in order to recommend reasonable rates, Staff adjusts test-year sales to "normal" weather. Climatological normal weather is generally characterized as an average daily temperature for each day, calculated over a 30-year period. The time period used by Staff to determine the normal values of weather variables in this case is the 30-year period (January 1, 1971 to December 30, 2000) used by the U. S. National Oceanic and Atmospheric Administration ("NOAA") and the World Meteorological Organization ("WMO") to calculate normal weather variables. Staff analysis of weather data shows in this case shows that the test year (January 1, 2009 - December 31, 2009) was approximately 3% warmer than "normal" for AmerenUE gas service area.

Natural gas sales are predominantly influenced by ambient air temperature, so daily average temperature and the derivative measure, heating degree days ("HDDs"), are the measures of weather used in adjusting natural gas revenues to determine what the Company's revenue would be in a "normal" weather year. Degree days are weather measures that were originally devised to evaluate the relationship between temperature and energy demand and consumption. Degree days are based on the variation of the daily average temperature (average of daily maximum and daily minimum) from a comfort level of 65 °F. HDDs are calculated as the number of degrees the daily average temperature is below 65 °F, and is equal to zero when the daily average temperature is above 65 °F.

To develop “normal” average temperatures and HDDs, Staff used weather records from NOAA weather stations. The two weather stations representing weather in AmerenUE service areas are the weather station at the Cape Girardeau Regional Airport, near Cape Girardeau, Missouri and the Columbia Regional Airport, near Columbia, Missouri. NOAA initially calculates monthly normal temperature variables (such as maximum, minimum, average temperatures, HDDs) over the 30-year normals period. These monthly normals are not directly usable for Staff’s purposes because NOAA’s daily normals are derived by statistically “fitting” smooth curves through these monthly values. As a result, the published values reflect smooth transitions between seasons. For weather normalization purposes Staff needs to examine seasonal variability because it affects usage throughout the year.

Consequently, Staff develops daily normal temperature variables by adjusting actual daily temperature data such that the average of the adjusted daily temperature variables corresponds with NOAA’s normal monthly average. Using these temperature variables, Staff calculates Normal and Actual HDDs to weather normalize gas usage. To determine daily normal HDDs Staff averages the adjusted daily actual HDDs for each calendar date. For example, the 30 observations of actual HDDs for January 1, of each year for the years 1971 through 2000, were averaged to determine the normal HDDs for January 1. The normal peak-day HDDs for each of the 12 months were calculated as the average of the HDDs of the coldest day in each of the 12 months.

Appendix 3, Schedules SJW-1, and SJW-2, presents calendar month summaries of the adjusted daily actual and normal HDDs during the test year for AmerenUE. The weather data shows that the test year (January 1, 2009 - December 31, 2009) was approximately 3% warmer than "normal" for AmerenUE's gas service areas. This information was made available to Staff witness Kim Cox to use in calculating Staff's weather normalization adjustment factor.

Staff Expert/Witness: Seoung Joun Won

g. Weather Normalization of Sales

1. Introduction and Summary

Because natural gas is predominately used for space heating in Missouri, sales are dependent upon weather conditions. Since rates are based on natural gas usage, it is important to remove the influence of abnormal weather from the test year. This analysis addresses Staff's weather-normalization of natural gas sales for AmerenUE customers in the Residential Class ("Res"), the Small General Service Class ("SGS") and the Large General Service Class ("LGS") for the test year ending December 31, 2009. Staff's overall weather normalization analyses resulted in increases to natural gas sales because the weather during the test year was warmer than normal. Staff's analyses resulted in an approximate increase of 2.42 percent for the residential customer class for weather and cycle days. Small general class resulted in an approximate increase of 2.78 percent for weather and cycle days. Large general class resulted in an approximate increase of 1.87 percent for weather and cycle days.

2. Process Used to Weather Normalize Sales

Staff's weather-normalized adjustments of natural gas sales correct for deviations from normal weather conditions that have occurred during the test year. Staff adjusted monthly natural gas volumes to normal by first equalizing each billing cycle's annual total normal heating degree days ("HDDs"). Staff then added or subtracted a number of days to make each billing cycle's annual total days equal to 365. This adjustment for days sets each billing cycle to the same total number of days and normal HDDs. Once each billing cycle has the proper normal

HDD, the second step is to calculate each billing cycle's difference between normal and actual HDDs. The third step is to multiply these differences times the estimate rendered from the regression analysis described in further detail below. The fourth step is to sum each billing cycle's adjustment volumes by billing month. The fifth step is to add the monthly adjustments in hundreds of cubic feet ("Ccfs") to the total monthly natural gas sales to calculate normalized volumes.

3. Application of Weather Normalization Process

Staff completed these calculations by first subdividing AmerenUE billing records into two geographic regions – Panhandle Eastern District ("PE") and Southeast District ("SE"). Staff witness, Mr. Seoung Joun Won, provided the daily actual and daily normal HDDs for each of the two geographic regions. Mr. Won addresses the calculation of HDDs as part of his section of this Cost of Service Report.

AmerenUE provided Staff with monthly natural gas sales in Ccf and the corresponding number of customers for each billing cycle by customer class and geographic region for each month of the test year. The Company groups natural gas accounts into billing cycles whose meters are to be billed throughout a month. The Company bills the accounts based on the meter reading. Since there are approximately twenty one (21) working days in a month, customers' accounts are usually grouped into one of the approximately twenty one (21) billing cycles. Staggering the billing of customers' accounts over the billing month spreads the amount of work necessary to bill AmerenUE customers. Staff calculated two sets of twelve billing month averages by customer class for the Residential, SGS and LGS in the two geographic regions specified above. One set of these averages was the daily average natural gas usage in Ccf and another set was the daily average HDD.

These billing month averages were calculated from the data on numbers of customers, natural gas usage in Ccf, and summed HDD from approximately twenty one (21) billing cycles for each billing month by customer class. Each billing month's daily average HDD in each billing cycle was weighted by the percentage of customers in that billing cycle. Thus, the billing cycles with the most customers are given more weight in computing the billing-month daily average HDD. Staff calculated twelve monthly average-usage-per-customer amounts across the billing cycles to calculate one month's daily average usage in Ccf. Staff's studies estimate the change in usage in Ccf related to a change in HDD. The study was based on two sets of twelve monthly billing month averages. One was the average daily usage in Ccf per customer and the other was the customer-weighted average daily HDD. These two sets of billing month averages (usage and weather) were used to study the relationship between space-heating natural gas usage in Ccf and colder weather.

Staff used regression analyses to estimate the relationship for each of the Residential, SGS and LGS customers in both geographic regions. The regression equation develops quantitative measures that describe the relationship between daily space-heating sales per customer in Ccf to the daily HDD. The regression equation estimates a change in the daily natural gas usage per customer whenever the daily average weather changes one HDD.

Staff's overall weather normalization analyses resulted in increases to natural gas sales because the weather during the test year was warmer than normal. Staff's analyses resulted in an approximate increase of 2.42 percent for the residential customer class for weather and cycle days. Small general class resulted in an approximate increase of 2.78 percent for weather and cycle days. Large general class resulted in an approximate increase of 1.87 percent for weather and cycle days. (Appendix 4, Schedules KC-1 through KC-9). This information was provided to

Staff witness Daniel I. Beck of the Commission's Energy Engineering Analysis Department for his calculation of total peak day demand. The adjustments include an increase of 0.7337% in sales for the Residential class and a decrease of 0.5291% in sales for the Small General class due to an Automated Meter Reading ("AMR") issue. These adjustments to natural gas sales do not include the Staff's customer growth annualization.

After calculating the adjustment to natural gas sales, Staff then applied the adjustment to AmerenUE's LGS blocks. AmerenUE's LGS rates are differentiated according to a commodity charge that is divided into two blocks. The first block is defined as the first 7000 Ccf of natural gas used in the month and the second block is defined as all volumes over 7000 Ccf per month. In order for Staff witness, Kofi A. Boateng, to compute the revenues associated with the normal volumes, the normal volumes must be properly allocated monthly to each block to determine the rate at which the volumes are to be computed.

The Company provided Staff with test year (November 2008 – December 2009) monthly active meters and monthly Ccf per customer ("Ccf/Cust") for the first block and total Ccf/Cust for the LGS rate code and customer class that will be served on the LGS tariff. Staff used the Company's test year first block Ccf/Cust and total Ccf/Cust to determine the normal usage falling into each rate block and the total usage for each month for the LGS rate class in the Panhandle Eastern District and the Southeast District.

The LGS customer class in each division monthly normal usage was estimated using regression analysis to compute a statistical relationship between cold weather and the Ccf/Cust. In the Panhandle Eastern District Staff observed that in the lower heating months of May through October the percent in the first block is nearly constant. In this district Staff used a simple average of the percent in the first block in the test year months May-October to estimate the normal percent in the first block for the months of May-October. For the remaining months, November-April, which have more heating use, Staff used regression analysis to estimate normal billing units in each month. For the Southeast District Staff used the average percent in the first block in the test year months November-December to estimate the normal percent in the first block.

Using the Company's test year monthly customer counts and bill frequencies for the LGS class, Staff used the monthly Ccf per customer per day in the test year months of November 2008 – December 2009 to estimate an equation that related it to the monthly percent use in the first block. Staff used normal monthly usage per customer in the regression equation to estimate the normal monthly percent in the first block. If the normal adjustments to the first and second blocks in a season were in opposite directions, the adjustment to the first block was set to zero and the total adjustment was assigned to the second block.

To compute the adjustment to test year volumes to yield the estimated normal volumes, Staff set the adjustment in the second block equal to the total minus the first block adjustment. The difference between the predicted normal usage volumes and test year volumes gives an estimated monthly adjustment for the first block.

Appendix 4, Schedules KC-10 and KC-11, contains the actual, normal and adjustment volumes for each billing month during the test year. The total adjustment for the Large General Service Class is 549,011 Ccf's. The total of these adjustments accounts for 100% of the adjustments made to both the first and second blocks. These adjustments were supplied to Staff witness, Kofi A. Boateng, for use in the customer growth revenue adjustment.

Staff Expert/Witness: Kim Cox

h. Weather Normalization of Transportation and Interruptible Sales

The sales volumes of Transportation and Interruptible customers were weather normalized due to their sensitivity to weather. The purpose of this was to remove the influence of abnormal weather from the test year since rates are based on natural gas usage. Staff used the weather normal usage per customer as computed by Staff witness Kim Cox.

Staff Expert/Witness: Michael L. Stahlman

i. Large Volume Service Customer Adjustments

AmerenUE provided monthly billing units and information for every customer who took service on the Interruptible Service, Small Standard Transportation Service, Large Standard Transportation Service, Large Volume Transportation Service, or Special Contract rates during the test year. Staff used these units as the basis of its analyses and adjustments of large customer sales. Based upon Staff's investigation and analysis of this information, Staff made adjustments to reflect the migration of customers to other rate classes ("rate switching") and the effect of weather on the Company's transportation and interruptible customers.

Staff Expert/Witness: Michael L. Stahlman

j. Rate Switching Adjustment

If a customer was in a rate class at the beginning of the test year and then transferred to a different rate class during the test year, the customer's billing determinants and associated revenues in the original class were removed from that class' totals. The customer's billing determinants were then "priced out" using the tariffed rate of the class to which the customer switched, and those determinants and revenues were added to the totals in the second class. This resulted in a full year of history for the customer in the rate class they were in at the end of the test year. This analysis is necessary in order to establish representative revenues on a going-forward basis and was performed in this case using information supplied by the Company for the test year. Staff has reviewed the Company's rate switch adjustment and agrees with their adjustment.

Staff Expert/Witness: Michael L. Stahlman

k. Industrial Customer Gains/Losses Adjustment

Adjustments to reflect customer gains and/or losses are made to the large customers' rate revenues. This adjustment reflects the effect of customers that either began taking service on the Company's system during the test year, or that quit taking service on the Company's system during the test year. The purpose of this adjustment is to provide a more accurate representation of the number of customers taking service in the class. If a customer came on the system, current revenues were adjusted for the 'missing' months. If a customer dropped off the Company's system, their revenues were removed from the current revenue calculation.

Staff Expert/Witness: Michael L. Stahlman

l. Special Contracts

As a general principle, Staff believes that customers should not have to pay for the discounts provided to a few select customers. Therefore, Staff has adjusted the special contract rates to better reflect an appropriate charge to those customers.

Staff Expert/Witness: Michael L. Stahlman

2. Operating and Maintenance Expenses

a. Payroll

Staff's annualized payroll for AmerenUE was based upon the test year ending December 31, 2009. Actual payroll expenses related to Missouri gas operations were adjusted for the following: (a) increases in wage rates that occurred both during the test year and through the September 30, 2010 true-up cut-off date for this case; and (b) the reduction of payroll expense that resulted from a reduction in employees caused by the voluntary separation election plan ("VSE") and an involuntary separation program ("ISP") implemented by the Company during 2009.

Staff's adjustments for operating and maintenance ("O&M") payroll expense were distributed by FERC account based upon the actual payroll distribution experienced by the Company during the test year ending December 31, 2009. Staff's Accounting Schedule 10, Adjustments to Income Statement Detail, reflects approximately 30 adjustments necessary to restate test year expense at an annualized level.

Staff Expert/Witness: Roberta A. Grissum

b. Incentive Compensation

1. Short Term Incentive Compensation

The Company has three distinct incentive compensation plans that are offered to employees: short-term compensation, long-term compensation, and an exceptional performance bonus program. Some of AmerenUE's incentive compensation costs are allocated from Ameren Services ("AMS"), as AMS provides various management and administrative functions to AmerenUE.

The short-term incentive compensation plan is broken-out into five categories as follows:

- Executive Incentive Plan - Officers,
- Executive Incentive Plan - Managers and Directors
- Ameren Manager Incentive Plan
- Ameren Marketing, Trading & Commodities, and
- Ameren Incentive Plan

The Executive Incentive Plan for Officers ("EIP-O") is designed to incentivize officers of the Company to ensure that they are focused on the overall success of the Company's business. These officers are senior level individuals who hold the positions of vice president, senior vice president, president and chief executive officer. The officers and the personnel with manager and director positions form the Ameren Leadership Team ("ALT"), a group that is responsible for the strategy and direction of all the functional areas within AmerenUE. Awards at this level are based upon the individual officer's personal performance and the achievement of certain scorecard key performance indicators ("KPIs") as determined by the Company. Such KPI measures may include AmerenUE's earnings, safety, reliability, and/or customer satisfaction. The Company's EIP-O is entirely funded by earnings per share ("EPS"), and has been disallowed by Staff.

The Executive Incentive Plan for Managers ("EIP-M") is a plan designed for members of the ALT, below the Officers level. Much like the EIP-O, the EIP-M awards are based upon participant's demonstrated leadership and contributions toward the achievement of the Company's business objectives. However, unlike the EIP-O, the EIP-M funding is based twenty-five percent on EPS and seventy-five percent is based on operational performance. The Company measured operational performance by KPIs and individual performance, as determined by supervisors through the performance appraisal process. Staff has disallowed the twenty-five percent of the EIP-M that is related to the EPS.

The Ameren Manager Incentive Plan ("AMIP") is designed for management employees and is funded entirely based on achievement of a set of KPIs. Like the EIP-M, payouts are based on the achievement of the participant's individual performance objectives and his/her contributions to the group's KPI measure. Similar to individual performance for the EIP-M, individual performance is determined by supervisors through the performance appraisal process. Staff has allowed the costs associated with this incentive program.

The Ameren Marketing, Trading & Commodities ("AMTC") plan is similar to the AMIP and is designed to target management employees who perform specific roles within the Company's trading and fuel divisions. This plan has two components: one, the base plan, which is identical to the AMIP; and two, the second component, called the supplemental plan, which provides group or position-specific measures for individuals within this group to achieve. The awards under the supplemental plan are converted into units of stock and are held for two years for the purpose of promoting employee retention before they are paid out. Staff has allowed the costs of associated with this incentive program.

The Ameren Incentive Plan ("AIP") is offered only to contract employees and -payout is determined by attaining specified KPI goals. It is designed to focus employees on areas that the employees are able to control. Staff has allowed the costs associated with this incentive plan.

The Exceptional Performance Bonus Plan ("EPBP"), unlike the short-term compensation plans, is not determined by either meeting a certain level of EPS or KPIs, but is awarded on the basis of outstanding performance of an individual as determined by his or her supervisor and approved by an officer. The process begins when a supervisor submits a recommendation, by completing a Performance Recommendation Form, to an officer that an employee be considered for a bonus on the basis of an exceptional performance. The supervisor who makes this recommendation also recommends the amount of bonus to be awarded. If this recommendation is approved, the employee is eligible for a bonus ranging from $500 to $4,000. However, EPB awards are not expected to exceed 10% of the employee's annual base pay in any contract year.

The criteria used by Staff to evaluate employee incentive plans were established in the Commission's Report and Order issued in *Re Union Electric Co.*, Case No. EC-87-114:

> At a minimum, an acceptable management performance plan should contain goals that improve existing performance, and the benefits of the plan should be ascertainable and reasonably related to the plan.
> 29 Mo. P.S.C. (N.S.) 313, 325 (1987).

Staff has reviewed AmerenUE's incentive compensation plans as described above and recommends that all incentive compensations that are directly tied to EPS be disallowed from the cost of service. This recommendation is consistent with past Commission rulings. In its Report and Order in *Re Kansas City Power & Light Company*, Case No. ER-2006-0314, at page 58, the Commission noted that, among other things, "because maximizing EPS could compromise service to ratepayers, such as by reducing customer service or tree-trimming costs, the ratepayers should not have to bear that expense." Again, in a recent AmerenUE rate case, Case No. ER-2008-0318, the Commission decided that, "AmerenUE shall not recover in rates the cost of its long-term compensation plan" for its executive officers, as the plan was based on EPS. These types of plans in the Commission's view "primarily benefit shareholders and not ratepayers".

Staff has made an adjustment to the test year incentive compensation expense consistent with the VSE and ISP which called for the elimination of certain management positions within AmerenUE and AMS.

In addition to the adjustment in the O&M expenses, Staff has made corresponding reductions in AmerenUE's plant in service and reserve balances to eliminate capitalized incentive compensation that relates to EPS.

Staff Expert/Witness: Kofi Agyenim Boateng

2. Long-Term Incentive Compensation: Restrictive Stock and Performance Share Units

In addition to the other types of compensation available (base and incentive), AmerenUE, through its parent company Ameren Corporation ("Ameren"), also offers its executives the possibility of restrictive stock awards and performance share units, and these form the Company's long-term compensation plans. Conditions are placed on the receipt of restrictive stock awards related to earnings performance. The performance share units program is based on the market performance of Ameren's common stock relative to a peer group of other companies' common stock, over a three-year period. Consistent with the Company's treatment of not seeking recovery in retail rates of these long-term incentive plans, Staff has eliminated all costs relating to these plans from its revenue requirement calculation.

Staff Expert/Witness: Kofi Agyenim Boateng

c. Other Employee Benefits

The Company currently offers employees medical, dental, vision, life insurance, long-term disability, and 401k benefits. Staff annualized employee benefits utilizing the actual employee benefits expense incurred during the 12-months ended August 31, 2010 adjusted to remove benefit costs associated with employees no longer with the Company due to VSE and ISP. The annualized level used by Staff in its cost of service is $2,148,455, an increase of $173,495 over the test year level of $1,974,960. In order to determine if further adjustments are appropriate Staff will continue to analyze actual costs through the September 30, 2010 true-up cut-off date as information becomes available.

Staff Expert/Witness: Roberta A. Grissum

d. Injuries and Damages Expense

Injuries and damages represent the portions of legal claims against a utility that are not subject to reimbursement under the utility's insurance policies. Injury and damage expenses are tracked in FERC Account 925. Staff reviewed the actual injuries and damages payment levels made by AmerenUE from January 2005 through December 2009 for gas operations. Based on the sporadic payment history, Staff determined that a three-year average for the period ending December 31, 2009 was the most appropriate reflection of recent experience and the best indication of an on-going level of these expenses to include in the Company's cost of service. As a result, Staff recommends a decrease to Account 925 in the amount of $343,820.

Staff Expert/Witness: Erin M. Carle

e. Insurance Expenses

AmerenUE obtains insurance protection from third-party insurance providers in order to help protect the utility, as well as ratepayers, against the risk of the financial loss associated with unanticipated events. Expenses associated with the purchase of insurance are tracked in FERC Accounts 924 and 925. For gas operations, AmerenUE purchases excess liability, workers' compensation, excess property and terrorism insurance. Staff adjusted AmerenUE's insurance expenses to annualize those expenses based on the premiums paid by the Company as of December 31, 2009. This resulted in an increase to Account 924 in the amount of $123,111 and an increase to Account 925 in the amount of $73,504. Staff intends to reexamine this level of expense for any changes in the cost of insurance through the September 30, 2010 true-up cut-off date, when that data becomes available.

Staff Expert/Witness: Erin M. Carle

f. Dues and Donations

Staff reviewed the list of membership dues paid, and donations made, to various organizations that AmerenUE charged to its utility accounts during the test year. Staff proposes adjustments to disallow various dues and donations that were included by AmerenUE in test year expenses. Such dues and donations were disallowed by Staff because they were not necessary for the provision of safe and adequate service, and thus do not have any direct benefit to ratepayers. Allowing the Company to recover these expenses through rates causes the ratepayer to involuntarily contribute to these organizations. In addition to disallowing certain costs, Staff also eliminated a 2008 annual membership fee for the American Gas Association that was included in the test year along with the annual fee for 2009. The Company was provided with a list of the dues and donations that clearly indicates the items Staff disallowed and/or eliminated from the test year as part of the Staff's workpapers.

In *Re: Missouri Public Service, a Division of UtiliCorp United, Inc.*, Case No. ER-97-394, et al., Report and Order, 7 Mo.P.S.C.3d 178, 212 (1998), the Commission stated:

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

Staff believes it has applied this guidance and these principles to the adjustments made for dues and donations in this case.

Staff Expert/Witness: Lisa M. Ferguson

g. Miscellaneous Expenses

AmerenUE books all miscellaneous expenses to the 900 Accounts. Staff reviews these expenses to determine if the items charged are necessary for Company operations and for the provision of safe and reliable service. Staff disallowed items such as finance charges and promotional items that are of no benefit to the ratepayer. As is the case regarding Staff's disallowance of dues and donations, the Company was provided with a list of the miscellaneous costs that clearly indicates the items Staff disallowed and/or eliminated from the test year as part of Staff's workpapers.

Staff Expert/Witness: Lisa M. Ferguson

h. Interest On Customer Deposits

Since the Staff is including customer deposits as a reduction to the rate base, it is also including the related interest expense in the cost of service. The interest expense is calculated at 1% plus the prime interest rate.

Staff Expert/Witness: Lisa M. Ferguson

i. Uncollectible ("Bad Debt") Expenses

Uncollectible expense is the portion of retail revenues that AmerenUE is unable to collect from its retail gas customers due to bill non-payment. This expense is tracked in FERC Account 904. After unsuccessful attempts to collect any outstanding debt, the Company will turn over delinquent accounts to a third-party collection agency. This assists in partial collections. Based upon Staff's investigation, Staff recommends an increase to Account 904 in the amount of $474,464.

In AmerenUE's previous gas rate case, GR-2007-0003, Staff discovered that for the years 2003, 2004, 2005, and 2006, AmerenUE had improperly charged all the collections of previously written-off gas accounts to its electric, as opposed to its gas operations. As part of its analysis in Case No. GR-2007-0003, Staff adjusted the actual level on net write-offs for 2003 – 2006 to include a portion of the collections previously charged to electric operations. For the purpose of Staff's analysis in the current case, Staff has also recognized those adjustments.

Staff Expert/Witness: Erin Carle

j. Rate Case Expenses

Rate Case Expense concerns the expenses incurred by the Company in the presentation of any case before the Commission. The regulated utility is entitled, under traditional ratemaking concepts, to rates that recover all reasonable and prudent amounts expended in rendering service, including costs incurred in establishing rates. Typical charges include office supplies, office support staff, outside consultants, and outside legal costs. After reviewing the list of charges and the associated cost the Company provided for its estimate of Rate Case Expenses for the current gas case, Staff is recommending a disallowance of the outside legal costs and the charges for the lead/lag study that was performed by an outside consultant. Staff believes AmerenUE has adequate legal in-house resources to process a gas rate case. No outside legal counsel was employed in the two previous gas rate cases that were filed separately from an electric rate case. With regard to the employment of an outside consultant to prepare a lead/lag analysis, Staff finds the $350,000 cost to be excessive, because extensive work was performed with regard to a lead/lag study in the recent AmerenUE electric rate case, ER-2010-0036. A significant portion of that analysis could have been adopted or only slightly modified for use in the current gas rate case. The Company is proposing to charge ratepayers more than it proposed in the most recent AmerenUE electric rate case. In light of the fact that AmerenUE has averaged filing a gas rate case approximately every three years, the Staff is proposing a three year amortization of the amount it is recommending for rate case expense in this case, which results in an annual expense level of $100,000.

Staff Expert/Witness: Lisa M. Ferguson

k. Accounting Standards Codification ("ASC") 715-30 (Formerly FAS 87) Pension Costs

1. ASC-715-30 Pension Tracker

In Case No. GR-2007-0003 Staff, AmerenUE and other parties entered into a Stipulation and Agreement ("the 2007 Agreement") that addresses the ratemaking treatment for annual qualified pension cost under Financial Accounting Standards Board's ("FASB") Accounting Standards Codification ("ASC") Subtopic 715-30 (formerly FAS 87). The 2007 Agreement requires AmerenUE to fund its qualified annual pension expense and track the difference between the annual pension expense and the level included in rates. The difference between the annual pension cost and the amount included in rates, as accumulated in the tracker, has been included in rate base and amortized over a period of five years as an addition or reduction to pension expense. Consistent with the Agreement approved in Case No. GR 2007-0003, Staff's rate base for AmerenUE is reduced for a regulatory liability in the amount of $266,710, which represents the over collection in rates of Subtopic 715-30 pension expense, compared to the actual expense incurred as of August 31, 2010. Staff has also included a reduction to pension expense in its income statement in the amount of $53,342 for the annual amortization, over five years, of the amount accumulated in the Subtopic 715-30 pension tracker. Based on information provided in a response to Staff Data Request No. 0137 and discussions with the Company, it has come to Staff's attention that AmerenUE is not funding the non-qualified portion of its pension expense, which relates to Ameren Supplemental Retirement Program. According to the Company, this plan is unfunded, and that the plan benefit payments are made on a monthly basis.

Given this information, Staff has proposed an adjustment to remove all the nonqualified pension expenses that are included in the tracker since its inception in Case No. GR-2007-0003. Staff is continuing to verify the amounts associated with the nonqualified plans, and may have to modify its adjustment based on this additional information.

Staff Expert/Witness: Kofi Agyenim Boateng

2. Annualization

Staff also annualized qualified pension expense to reflect the projected FASB ASC Subtopic 715-30 (formerly FAS 87) cost provided by AmerenUE's actuary, Towers Perrin. This level should be the amount used in the pension tracker, after rates are established in this case, to determine the difference between pension expense included in rates and the amount actually incurred and funded by AmerenUE.

Additionally, the Company's pension expense includes the cost related to non-qualified plans described as the Ameren Supplemental Retirement Program, which is designed for selected AmerenUE executives. Since this plan is not funded, only the actual payments made during the test year were used as expense for this retirement program.

Since some of AmerenUE's management and administrative functions are provided by AMS employees, AmerenUE's pension expense includes costs that are allocated from AMS.

Staff Expert/Witness: Kofi Agyenim Boateng

l. ASC 715-60 (formerly FAS 106) OPEBs

1. ASC 715-60 OPEBs Tracker

The 2007 Agreement also addresses the ratemaking treatment for the annual OPEBs cost under FASB's ASC Subtopic 715-60 (formerly FAS 106). As with ASC 715-30 (discussed above), the 2007 Agreement requires funding of the qualified annual OPEB expense and establishes a tracker for the difference between the amount of OPEB expense in rates and the actual expense incurred. Consistent with the 2007 Agreement approved in Case No. GR 2007-0003, Staff's rate base for AmerenUE is reduced for a regulatory liability in the amount of $2,058,977, which represents the overcollection in rates of ASC 715-30 OPEBs expense, compared to the actual expense incurred. This amount was calculated based on the estimated balances projected as of August 31, 2010. Staff has also included a reduction to pension expense in its income statement in the amount of $411,795 for the annual amortization, over five years, of the amount accumulated in the ASC 715-60 OPEBs tracker.

2. Annualization

Staff also annualized OPEB expense to reflect the projected ASC 715-60 cost provided by AmerenUE's actuary, Towers Perrin. This level will be the amount used in the OPEB tracker, after rates are established in this case, to determine the difference between

ASC 715-60 expense included in rates and the amount actually incurred and funded by AmerenUE. Since some of AmerenUE's management and administrative functions are provided by AMS employees, AmerenUE's OPEB expense includes costs that are allocated from AMS.

Staff Expert/Witness: Kofi Agyenim Boateng

m. Short-term Debt Facility Fees

In AmerenUE's recent electric rate case, ER-2010-0036, the Commission approved a stipulation and agreement regarding the appropriate treatment of short-term debt facility fees. In that case the parties agreed that the cost of facilities fees should be treated as a cost of short-term debt. Since short-term debt is generally used to finance construction, the fees to secure that debt should be capitalized as a cost of plant. Staff is recommending that the treatment used in the electric rate case for facility fees also be used in the current proceeding. Therefore, Staff has removed the allocated gas portion of facility fees from expense and this amount will be capitalized as a cost of future gas plant.

Staff Expert/Witness: Stephen M. Rackers

n. Energy Efficiency and Weatherization Programs

In the 2007 Stipulation, the parties agreed to include funding for weatherization in the amount of $263,000 and for energy efficiency in the amount of $100,000. However, during the test year the Company was not booking these amounts to O&M expense. Therefore, Staff has increased expense by $363,000 to include the approved amounts in the cost of service. In addition, Staff is also examining the level of actual expenditures for energy efficiency in comparison to the amount collected in rates. Based on the results of this analysis, further adjustments for energy efficiency may be required. Any changes to the ongoing level of funding or the terms of these programs will be discussed in the testimony of Staff witness Michael L. Stahlman, who will be filing testimony related to the Rate Design phase of this proceeding on November 19, 2010.

Staff Expert/Witness: Stephen M. Rackers

o. PSC Assessment

Each year, the Commission makes an estimate of the expenses to be incurred during the upcoming fiscal year that are reasonably attributable to the regulation of public utilities. This assessment is levied against specific utility companies regulated by the Commission per Section 386.370, RSMo (2000). The amount per company varies based upon a number of factors, such as industry activity for the preceding fiscal year and individual utility company's gross intrastate operating revenue for the previous calendar year as a percentage of the particular utility industry's total gross intrastate operating revenue. Based upon Staff's investigation, AmerenUE's assessment for their gas operations is expected to be lower than those incurred in the test year. As a result, a negative adjustment was included in the cost of service to reflect the lower ongoing expense.

Staff Expert/Witness: Lisa M. Ferguson

3. Depreciation Expense

Staff adjusted the level of depreciation expense based on the rates recommended by Staff witness David Williams of the Engineering and Management Services Department. The rates provided were applied to the estimated level of plant in service at the true-up cut-off date, September 30, 2010. As part of its adjustment, Staff also eliminated the portion of depreciation charged to construction that is associated with transportation and power operated equipment used in the construction process. This depreciation is not charged to expense, but will be reflected in future plant balances. The portion of depreciation expense that was charged to O&M expense was increased to reflect the increase in depreciation rates on transportation and power-operated equipment used in the maintenance process.

Staff Expert/Witness: Lisa M. Ferguson

4. Amortization Expense

a. Equity Issuance and Severance cost

In AmerenUE's recent electric rate case, ER-2010-0036, the Commission approved a stipulation and agreement regarding the amortization of severance cost and equity issuance costs incurred in 2009. In that case the severance cost was amortized over 3 years and the issuance cost was amortized over five years. Staff is recommending that the same treatment and amortization periods used in the electric rate case be afforded these items in the current proceeding. Therefore, Staff has included the allocated gas portion of these amortizations in the cost of service in the current rate case.

Staff Expert/Witness: Stephen M. Rackers

b. Pensions OPEBs Trackers

See discussion of these amortizations in sections VI. G. 2. k. and i.

Staff Expert/Witness: Kofi Boateng

5. Other Taxes

a. Property Taxes

For property assessment purposes, each utility company is required to file with its respective taxing authority a valuation of utility property at the beginning of each assessment year (January 1). Several months later, based on the information provided by the utility, the taxing authority will send the company what is known as "assessed values" for every category of the company's property. The taxing authority will issue to the utility company a property tax rate later in the year. Finally, the taxing authority issues a property tax bill to the company late in each calendar year with a "due date" of December 31. The billed amount of property taxes is based on the property tax rate applied to the previously determined assessed values of the utility's plant in service balances as of January 1 of the same year. Staff developed its property tax rate based on the Company's estimate of the 2010 taxes, which are paid based on investment existing as of January 1, 2010. The reasonableness of this estimate was verified based on an examination of the taxes paid during the test year and the increases in both plant and assessed values.

Staff Expert/Witness: Lisa M. Ferguson

b. Corporate Franchise Taxes

Corporate franchise tax is paid by corporations in advance for doing business within the state. Corporate franchise tax is based on the par value of the corporation's outstanding shares and surplus. Staff increased corporate franchise tax to reflect the slightly higher on-going level of expense.

Staff Expert/Witness: Lisa M. Ferguson

c. Payroll Taxes

During the test year ending December 31, 2009, the Company over-accrued Federal Insurance Contributions ("FICA") Old Age Survivors and Disability Insurance ("OASDI") and FICA Medicare payroll taxes by an amount of $1,216,592. Therefore, the amount included by Staff for annualized payroll taxes reflects the following: (a) a reduction of test year level FICA payroll tax in the amount of ($1,216.592) to correct the over-accrual that occurred during the test year; (b) an increase in FICA payroll tax in the amount of $22,348 to annualize FICA payroll taxes to reflect the wage increases included in Staff's annualized payroll expense; and (c) a reduction to FICA for the effect on payroll taxes related to VSE and ISP. The result of Staff's payroll tax adjustment is a decrease to expense of ($1,203,971) resulting in an annualized payroll tax expense level of $709,840 in Staff's cost of service.

Staff Expert/Witness: Roberta A. Grissum

d Gross Receipts Taxes

See the discussion in Section VI.G.l.c.

Staff Expert/Witness: Kofi Boateng

F. Income Tax Expense – Accounting Schedule 11

Staff's calculation of total cost of service income tax expense under existing rates is reflected on Accounting Schedule 11. The federal and state income tax reflects the current corporate federal income tax rate of 35% and the current corporate Missouri state income tax rate of 6.25%. The city income tax reflects the effective tax rate that considers the level of income generated in the City of St. Louis and any applicable credits.

As shown on Accounting Schedule 11, Staff has calculated income tax expense by applying the noted federal, state and city income tax rates to AmerenUE's operating income before taxes, less interest expense synchronized with Staff's recommended rate base and cost of capital recommendation.

At the end of Accounting Schedule 11, Staff shows the calculation of deferred income taxes. These items reflect amortizations of previously deferred taxes and investment tax credits.

Staff Expert/Witness: Stephen M. Rackers

VII. DEPRECIATION RATES

Summary

Staff conducted a depreciation study of the capital assets of AmerenUE, including an analysis of the accumulated reserve for depreciation. Based on its study, Staff recommends depreciation rates for the Company as indicated in Appendix 5, Schedule DCW-1, attached to this Report.

Staff's proposed depreciation rates for AmerenUE would decrease the current ordered annual depreciation expense from approximately $8,975,222 to $8,804,427, as indicated in Appendix 5, Schedule DCW-2. The recommendation represents a total decrease of $170,795.

Appendix 5, Schedule DCW-3 lists, by plant account, Staff's proposed depreciation rates. This schedule also provides a comparison of Staff's recommended new depreciation rates to the current rates, which the Commission ordered in Case No. GR-2007-0003, effective April 1, 2007.

Appendix 5, Schedule DCW-4 lists, by plant account, the accumulated reserve for depreciation and the theoretical reserve amount. Staff's study indicates an over-accrual of the accumulated reserve for depreciation of approximately $15,563,874.

A. Depreciation Principles

"Depreciation" as applied to depreciable utility plant means the loss in service value, not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service, from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand 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. Recovery of 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, known as 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 also 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 does not recommend any amortization of the excess accrual at this time, but will continue to monitor the balance. Staff uses the following formula to calculate a depreciation rate for each plant account:

$$\textit{Depreciation Rate} = \frac{100\% - \%\ \textit{Net Salvage}}{\textit{Average Service Life (years)}}$$

This is consistent with the Commission's depreciation rate formula contained its Report and Order in The Empire District Electric Company Case No. ER-2004-0570. As shown in the formula, the average service life and net salvage percentage are the depreciation parameters used to determine the depreciation rate. 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 in Appendix 5, Schedule DCW-1. That determination 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., meters) regardless of when that unit was first put into service (also referred to as its "placement date"). An account's ASL is developed in four steps. The first step is to review historical mortality data and historical salvage and cost of removal data. The data is checked for reasonableness, and to determine whether or not sufficient data exists 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 another historical database.

The second step is to gain familiarity with the Company's facilities and to discuss current trends and developments that may influence the useful life of plant-in-service with Company 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.

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 a Company's plant accounts, Staff uses depreciation software to analyze historical plant data by calculating the ratio of retirements to exposures by age, and solve for the percent surviving by age to develop a survivor curve for an account. Data regarding plant additions in dollars by year, or vintage, and retirements from each vintage, in dollars by year, are necessary for this analysis. 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 an Iowa curve.[22] Smoothing the original survivor curve by fitting it to an Iowa curve eliminates irregularities and extrapolates stub curves to zero percent. 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 to apply Staff's 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 recommends the ASLs, by account, identified in Appendix 5, Schedule DCW-1.

As noted earlier the average service life is just one of two factors determining a given depreciation rate.

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 of removal) that property in an account may experience. The net salvage equation is expressed as follows:

Net Salvage = Gross Salvage - Cost of Removal

Gross salvage is the recovered market 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

[22] 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. 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.

as an expense or net cost of removal. A negative net salvage percentage is commonly referred to as a net cost of removal percentage. Today, many utility 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 precedent for net salvage from its Report and Order issued in The Empire District Electric Company Case No. ER-2004-0570.

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.

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, in this case, December 31, 2008.

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 and 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 recommended by Staff will differ from the ASL that occurs.

F. Recommendations

Staff recommends that the Commission order the depreciation rates proposed in Appendix 5, Schedule DCW-1. Staff also recommends that AmerenUE be ordered to follow the precedent and guidance sought and received in Case No. ER-2004-0570, that a separate accounting be kept of its amounts accrued for recovery of its initial investment in plant from the amounts accrued for the cost of removal. Staff's recommendation addresses the Commission's precedent as stated in Case No. ER-2004-0570. Staff's proposed depreciation rates for AmerenUE would decrease the current ordered annual depreciation expense from approximately $8,975,222 to $8,804,427, as indicated in Appendix 5, Schedule DCW-2. The recommendation represents a total decrease of $170,795. Under the traditional accrual method, the depreciation rate for a particular asset or group of assets is calculated as follows:

$$\textit{Depreciation Rate} = \frac{100\% - \%\ \textit{Net Salvage}}{\textit{Average Service Life (years)}}$$

In this formula, net salvage equals the gross salvage value of the asset minus the cost of removing the asset from service. The net salvage percentage is determined by dividing the net salvage experienced for a period of time by the original cost of the property retired during that same period of time. This is the accrual method used by Staff to determine the depreciation rate.

Staff Expert/Witness: David Williams

APPENDICES

Appendix 1 - Staff Credentials

Appendix 2 - Support for Staff Cost of Capital Recommendation - Zephania Marevangepo

Appendix 3 - Weather Normal Variables Used for Weather Normalization - Seoung Joun Won

Appendix 4 - Weather Normalization of Sales - Kim Cox

Appendix 5 - Depreciation Rates - David Williams

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Natural Gas Service Provided to Customers in the Company's Missouri Service Area	)))))	Case No. GR-2010-0363

AFFIDAVIT OF KOFI AGEYENIM BOATENG

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Kofi Ageyenim Boateng, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 29-31, 40-44, 49-51, 54 and 55; 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 Ageyenim Boateng

Subscribed and sworn to before me this 5th day of November, 2010.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

Nikki Senn
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Natural Gas Service Provided to Customers in the Company's Missouri Service Area	)))))	Case No. GR-2010-0363

AFFIDAVIT OF ERIN M. CARLE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Erin M. Carle, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 45 and 47 - 48; 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 M. Carle

Erin M. Carle

Subscribed and sworn to before me this 5th day of November, 2010.

Nikki Senn

Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Natural Gas Service Provided to Customers in the Company's Missouri Service Area	)))))	Case No. GR-2010-0363

AFFIDAVIT OF KIM COX

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Kim Cox, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 33 - 37; 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.

Kim Cox
Kim Cox

Subscribed and sworn to before me this 5th day of November, 2010.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
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Nikki Senn
Notary Public

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OF THE STATE OF MISSOURI

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AFFIDAVIT OF LISA M. FERGUSON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Lisa M. Ferguson, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 23-27, 46-47, 48-49, 52-53 and 54-55; 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 M. Ferguson
Lisa M. Ferguson

Subscribed and sworn to before me this 5th day of November, 2010.

Nikki Senn
Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
Commission Number: 07287016

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AFFIDAVIT OF ROBERTA A. GRISSUM

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Roberta A. Grissum, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report in pages 39-40, 44 and 55 ; 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.

Roberta A. Grissum

Roberta A. Grissum

Subscribed and sworn to before me this 5th day of November, 2010.

Nikki Senn

Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
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AFFIDAVIT OF ZEPHANIA MAREVANGEPO

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Zephania Marevangepo, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 4 through 21; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Zephania Marevangepo

Subscribed and sworn to before me this 5th day of November, 2010.

Nikki Senn
Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
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AFFIDAVIT OF STEPHEN M. RACKERS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Stephen M. Rackers, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 1-4, 22-23, 27-28, 51-52, 53-54 and 56; 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.

Stephen M. Rackers
Stephen M. Rackers

Subscribed and sworn to before me this 5th day of November, 2010.

Nikki Senn
Notary Public

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
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AFFIDAVIT OF MICHAEL STAHLMAN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Michael Stahlman, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 38-39; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Michael Stahlman

Subscribed and sworn to before me this 5th day of November, 2010.

NIKKI SENN
Notary Public - Notary Seal
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Nikki Senn
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AFFIDAVIT OF DAVID WILLIAMS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

David Williams, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 56 through 63; 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 Williams
David Williams

Subscribed and sworn to before me this 5th day of November, 2010.

NIKKI SENN
Notary Public - Notary Seal
State of Missouri
Commissioned for Osage County
My Commission Expires: October 01, 2011
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Nikki Senn
Notary Public

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AFFIDAVIT OF SEOUNGJOUN WON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Seoungjoun Won, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 31-33; 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.

Seoungjoun Won

Subscribed and sworn to before me this 5th day of November, 2010.

NIKKI SENN
Notary Public - Notary Seal
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Notary Public