Exhibit No. 100

MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

REVENUE REQUIREMENT COST OF SERVICE

KCP&L GREATER MISSOURI OPERATIONS COMPANY

CASE NO. ER-2016-0156

Jefferson City, Missouri
July 15, 2016

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

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I. Executive Summary

On February 23, 2016, KCP&L Greater Missouri Operations Company ("GMO") applied to increase its retail rates, requesting an increase in revenues of $59.3 million – an expected increase in rates of approximately 8.17% -- and a return on equity ("ROE") of 9.9%. If granted, this revenue requirement would produce an approximate 8.17% increase over current revenues of $725.9[1] million. Also in its Direct Filing, GMO proposed consolidated rate schedules and tariffs for electric service for the L&P and MPS rate districts.

Staff reviewed all cost-of-service components (capital structure, return on rate base, rate base, depreciation expense and operating expenses) that comprise GMO's revenue requirement based on the 12-months ending December 31, 2015. Historically, GMO has kept separate books for its MPS and L&P rate districts. Some GMO costs were allocated between two rate districts, while most were directly assigned. GMO's revenues were accounted for separately as MPS and L&P. In this case, Staff recommends that the Commission eliminate GMO's separate rate districts and, instead, order rates that apply throughout GMO's service territory. Since, historically, GMO's cost of service was allocated or assigned between the MPS and L&P rate districts, it was necessary to analyze the rate districts separately and then sum the results to derive a GMO consolidated revenue requirement.

Staff recommends a ROE range of 8.65% to 9.35%, with a mid-point of 9.00%, which yields the rate of return range of 6.99% to 7.34%, with a mid-point overall of 7.16%. Staff's revenue requirement for GMO at the mid-point which, is based on GMO's actual costs through December 31, 2015, is an increase of $3,665,338 over its current revenues recovered from retail rates of approximately $736,000,000. The *Order Setting Procedural Schedule* provided for a true-up date of July 31, 2016. Staff has included a "plug" of $35,000,000 based on its current

[1] Direct Testimony of Darrin R. Ives, page 5.

estimate of the impact of true-up items on revenue requirement. Staff's EMS run results that support its revenue requirement for GMO are presented in the Accounting Schedules that are separately filed as an exhibit in the case concurrently with this Report.[2]

Below are definitions of technical terms that will frequently be used in the Cost of Service Report.

Test Year: The test year income statement is the starting point for determining a utility's existing annual revenues, operating costs and net operating income. In this case, the test year is the 12 months ending June 30, 2015.

Update Period: It is a standard practice in ratemaking in Missouri to utilize a period beyond the established test year for a case in which to match the major components of a utility's revenue requirement. The update period that was agreed to for this particular case is the 12 months ending December 31, 2015.

True Up: A true-up date generally is established when a significant change in a utility's cost of service occurs after the end of the update period, but prior to the operation-of-law date, and one or more of the parties has decided this significant change in cost of service should be considered for cost-of-service recognition in the current case. True-up audits involve the filing of additional testimony and, if necessary, additional hearings beyond the initial testimony filings and hearings for a case. The true-up date ordered in this case is July 31, 2016.

Normalization: Utility rates are intended to reflect normal ongoing operations. A normalization adjustment is required when the test year reflects the impact of an abnormal event. For example, overtime expense may be normalized to remove an unusual weather event, and revenues may be normalized to remove abnormal weather conditions.

Annualization: Annualization adjustments are the most common adjustment made to test year results to reflect the utility's most current annual level of revenue and expenses. Annualization adjustments are required when changes have occurred during the test year and/or update period, which are not fully reflected in the unadjusted test year results. For example, signing a new labor contract would necessitate annualizing the new level of wages to expense. Similarly, an addition of a large industrial customer would necessitate an annualization of billing determinants and revenues.

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[2] Standalone accounting schedules for MPS and L&P are attached to GMO's consolidated accounting schedules are filed in Appendix 4 of this Cost of Service Report.

Disallowances: In examining test year results, Staff makes disallowances to costs that should not be recovered in rates. Examples of these types of costs are certain advertising costs and donations made to charitable organizations.

Return on Equity: The ROE is the return allowed in rates on the shareholders' equity investment in a regulated utility.

Rate of Return: The ROR is the overall cost capital; that is, the cost of debt and the Commission-selected ROE weighted by the capital structure.

Short forms used in the Staff's Revenue Requirement Report and Class Cost-of-Service Report include:

"Commission" for the Missouri Public Service Commission;

"Staff" for the Staff of the Missouri Public Service Commission;

"Public Counsel" for the Office of the Public Counsel;

"GMO" for KCP&L Greater Missouri Operations Company;

"GMO Consolidated" for the consolidation of GMO's MPS and L&P rate districts.

"GMO's MPS rate district" for GMO's service territory in and about Kansas City and Sedalia, Missouri;

"GMO's L&P rate district" for GMO's service territory in and about St. Joseph, Missouri;

"Great Plains" for Great Plains Energy, Inc.;

"KCPL" for Kansas City Power & Light Company.

"EMS" for Staff's revenue requirement model referred to as Exhibit Modeling System

Staff Expert/Witness: Robin Kliethermes

II. Brief Background on GMO

GMO is an integrated, regulated electric utility that provides generation, transmission, and distribution services. GMO sells electricity at retail to customers in the northwestern, central western, and southern part of Missouri, participates in the SPP integrated market, and participates in FERC-jurisdictional contracts. Currently, GMO's total company cost of service is allocated to two rate districts -- MPS and L&P – each district having a discrete schedule of rates for similarly-situated customers. GMO is a wholly-owned subsidiary of Great Plains. Great Plains is a holding company incorporated in Missouri in 2001. It has two wholly-owned subsidiaries -- KCPL and GMO -- that provide regulated retail utility services in Missouri.[3] On the advice of counsel, GMO is an "electrical corporation" and a "public utility" within the intendments of Section 386.020, RSMo., and is therefore subject to the jurisdiction of the Commission. Great Plains is a public utility holding company regulated under the Public Utility Holding Company Act of 2005, which was enacted as part of the Energy Policy Act of 2005. Great Plains does not provide electric service to retail customers.

Following a 2008 restructuring, KCPL employees perform all the work for Great Plains and its subsidiaries, including GMO.

Staff Expert/Witness: Robin Kliethermes

III. Overview of GMO Consolidation

The Commission issued on November 7, 2012, its *Order Incorporating Unopposed Non-Unanimous Stipulation and Agreement* as to Certain Issues, incorporating the agreement filed October 19, 2012, in Case Nos. ER-2012-0174 and ER-2012-0175, as modified. On pages 10 – 11 of that stipulation, the parties agreed that:

> GMO will perform, prepare and file in its general electric rate case the results of a comprehensive study on the impacts on its retail customers of eliminating the MPS and L&P rate districts and implementing company-wide uniform rate classes, and rates and rate elements for each rate class, taking into account the potential future consolidation of GMO rates with those of KCPL. In this study, GMO will provide a distribution of rate impact on each of its customers of moving from MPS to L&P rate structures, and rate elements, and likewise, from L&P to MPS rate structures, and rate elements. If GMO would prefer a class rate structure that is different from a current MPS or L&P class rate structure, then individual customer impacts should be provided for the rate structure that GMO proposes.

GMO supplied various levels of analysis regarding rate consolidation in this case, and Staff will discuss them in more detail in Staff's Rate Design and Class Cost of Service Report to be filed on July 29, 2016.

Staff recommends moving to a company-wide revenue requirement and uniform rate classes because at currently tariffed rates, the similarly-situated customers in the MPS or L&P

[3] KCPL also provides retail electric service in the state of Kansas. On May 31, 2016, Terry Bassham, CEO of GPE, advised the Commission and Staff by email that GPE and Westar Energy, Inc., had entered into an agreement for GPE to acquire Westar for $8.6 billion in cash and stock.

rate district could have a higher or lower bill depending on the specific usage and demand characteristics of that customer, in other words, similarly-situated customers in the MPS and L&P rate districts are much more likely to have similar bills today than would have been the case prior to Case No. ER-2012-0175. This is particularly true for residential customers. As Staff will discuss in Staff's Class Cost of Service and Rate Design Report, while noticeable changes remain in the rate structures of the two rate districts, the historical distinction in bills for similarly-situated customers that existed as a legacy of pre-merger rate base investments has been largely eroded, or even reversed. Historically, for most customers in most classes, the tariffed rates for the MPS rate district produced noticeably higher bills than those incurred by similarly-situated customers served under the tariffed rates for the L&P rate district. As of the rates implemented in Case No. ER-2012-0175 that is no longer the case.

Staff Expert/Witness: Robin Kliethermes

IV. Economic Considerations

The indicators of Missouri's general economic condition, as well as those for the counties where GMO provides electric service,[4] indicate that moderate growth continues. Figure 1 below shows that the real gross domestic product ("GDP") growth of Missouri has averaged less than one percent (1%) per year from 2010 to 2015. Preliminary 2015 data had shown a robust year-over-year growth rate at 2.80 percent, but subsequent revisions lowered the growth to only 1.29 percent.

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[4] According to the minimum filing requirements submitted to the Missouri Public Service Commission, GMO serves 31 counties in Missouri. This report does not include the 13 counties in the KCPL service area.

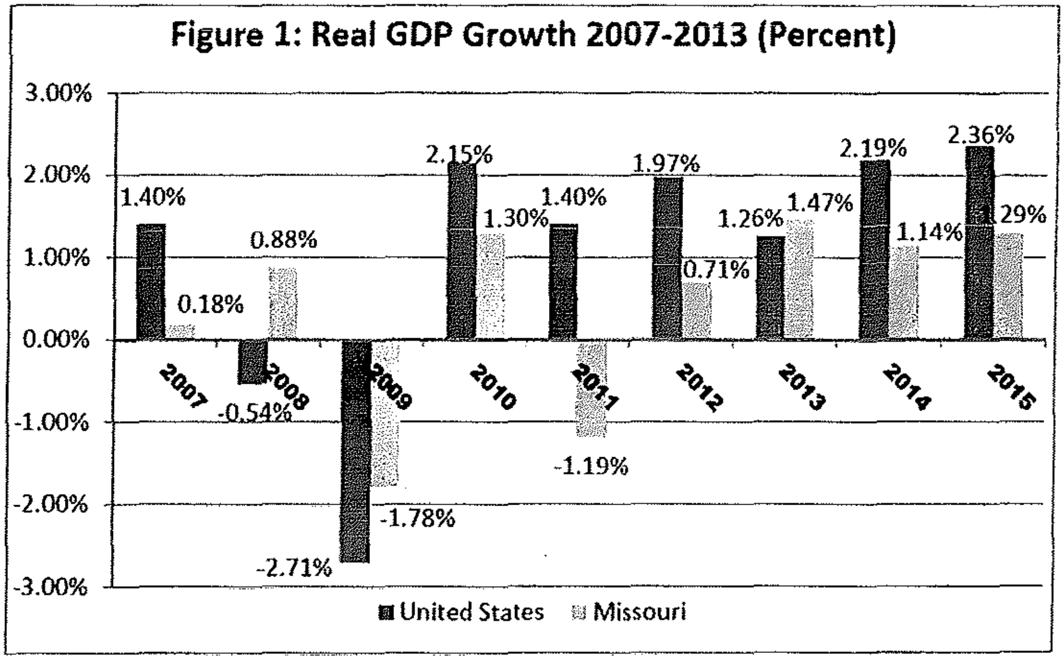

Figure 1: Real GDP Growth 2007-2013 (Percent)

Despite a low GDP growth rate, Figure 2 shows that the annual unemployment levels for the GMO service territory and Missouri are at the pre-recession levels.[5] Figure 2 also includes the unemployment data for GMO's service territory. The L&P rate district has historically had a lower unemployment rate, but is only about 16% of the total employment in GMO service territory.[6] There appears to be a high correlation between the unemployment rates for the GMO service territory, Missouri, and the United States ("U.S."), but the unemployment rate for the U.S. rates have yet to reach the pre-recession lows.

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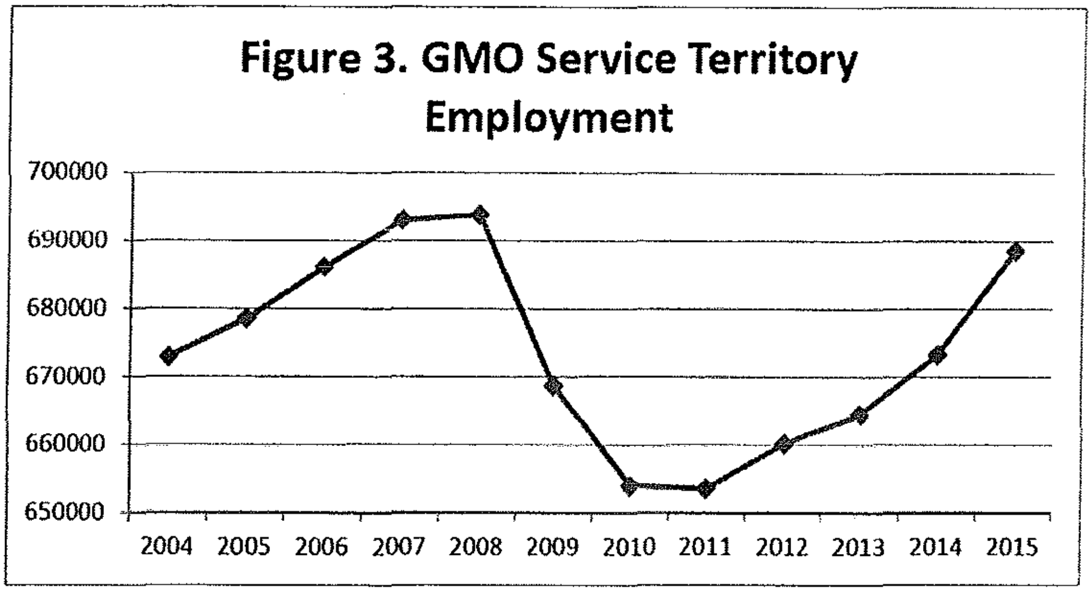
[5] According to the National Bureau of Economic Research, the recession began in December 2007 and ended in June 2009.

[6] MPS and L&P represent the former Missouri Public Service and St. Joseph Light & Power service territories, respectfully. The MPS rate district includes the counties of Barton, Bates, Benton, Buchanan, Carroll, Cass, Cedar, Clay, Clinton, Dade, Daviess, Grundy, Harrison, Henry, Jackson, Johnson, Lafayette, Livingston, Mercer, Pettis, Platte, Ray, St. Clair and Vernon. The L&P rate district includes the counties of Andrew, Atchison, Buchanan, Clinton, DeKalb, Gentry, Holt, Nodaway, Platte and Worth.



In addition to examining the status of the current economy, economic forecasters also examine economic data that have a history of leading, lagging, or coinciding with changes in the broader economy to anticipate future economic conditions. The current economic outlook from a variety of economic forecasters has been less than optimistic. For instance, the American Institute for Economic Research's ("AIER")[7] most recent version of Business Cycle Conditions (June 2016) shows that 50 percent of the leading indicators are evaluated as expanding.[8] Under AIER's method, consistent evaluations above 50 percent suggest a low probability of recession over the next six to 12 months. The prior two months were at 38, a level that indicated economic weakness, but not sufficient to conclude a recession was imminent. AIER states that this "rebound suggests the risk of recession has receded but remains slightly elevated."[9] Further, CITI's 2016 outlook released December 1, 2015 estimated a 65 percent chance of a U.S. recession in 2016.[10]

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[7] American Institute for Economic Research (09JUN16). "Business Conditions Monthly" https://www.aier.org/bcmoverview2016june (28JUN16).

[8] AIER uses 24 indicators in total – 12 leading indicators are a measurable economic factor that tend to change ahead of a turning point in the broader economy, six coincident indicators that tend to change at roughly the same time as a change in the broader economy, and six lagging indicators that tend to change after a turning point in the broader economy. AIER recently revised its list of indicators, details of which can be found at https://www.aier.org/revising . A leading indicator evaluated as expanding means that the change in that indicator is historically correlated with future economic growth.

[9] American Institute for Economic Research (09JUN16). "Business Conditions Monthly" https://www.aier.org/bcmsummaryappendix2016june (28JUN16).

[10] The outlooks are for the U.S. economy in general and may not reflect the outlook in any specific sector.

Figure 4 provides a comparison of the increase in average weekly wages for the counties in the GMO two rate districts, the Consumer Price Index ("CPI"), the Producer Price Index ("PPI")[11], and GMO's electric rates in its two rate districts. From 2007 to 2015, the counties in the GMO's service territory collectively experienced an 18.6 percent increase in average yearly wages; 18.5 percent in the MPS rate district and 23.8 percent in the L&P rate district. The overall Missouri increase in average yearly wages over that period was 18.0 percent. However, during that same time period, electric rates for residential customers served by GMO increased in Case Nos. ER-2007-0004, ER-2009-0090, ER-2010-0356, ER-2012-0024, and ER-2012-0175, a cumulative total of 38.56 percent for MPS customers and 76.73 percent for L&P customers, which accumulated to a total increase of approximately $239.4 million for the GMO service territory as a whole, as shown in Table 1.

GMO has also experienced inflationary pressure illustrated by a 10.31 percent increase in the PPI for industrial commodities from 2007 to 2015.[12] GMO is currently requesting to eliminate its MPS and L&P rate districts for territory-wide rates designed and to increase its rate revenues by an additional $59.3 million per year, or an 8.17 percent increase. From 2007 to 2015, the increase in average yearly wages for counties in the MPS rate district is less than one-half of the increase in electric rates, and the increase in average yearly wages for counties in the L&P rate district is less than one-third of the increase in electric rates. If GMO receives its requested 8.17 percent increase, based on its current rate districts, the increase in average weekly wages would be just over one-third of the increase in electric rates for the MPS rate district and just over one-fourth of the increase in electric rates for the L&P rate district.

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[11] The PPI represents the Producer Price Index for Industrial Commodities which includes textile products and apparel, hides, skins, leather and related products, fuels and related products and power, chemicals and allied products, rubber and plastic products, lumber and wood products, pulp, paper and allied products, metals and metal products, machinery and equipment, furniture and household durables, nonmetallic mineral products and transportation equipment.

[12] Detailed information on GMO's expenditures and revenues can be found later in the Staff Cost of Service Report.

Figure 4: Comparison of Weekly Wages, CPI, PPI and Electric Rates

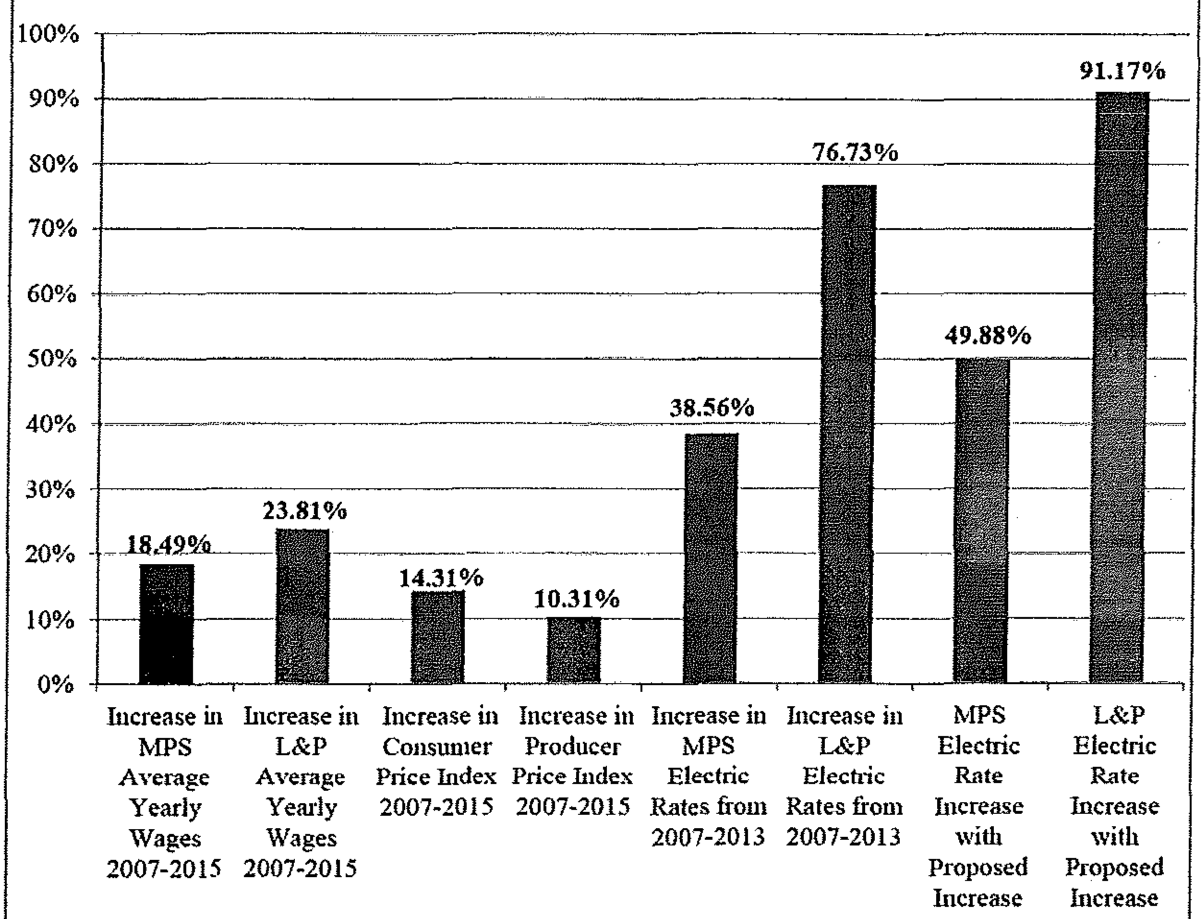

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Table 1: GMO Rate Case History 2007-2016

Case Number	Effective Date	Dollar Value MPS	Dollar Value L&P	%Increase MPS	%Increase L&P
ER-2007-0004					
GMO-L&P	May 31, 2007		$13,583,654		12.79%
GMO-MPS	May 31, 2007	$45,253,654		11.64%	
ER-2009-0090					
GMO-L&P	September 1, 2009		$15,000,000		11.85%
GMO-MPS	September 1, 2009	$48,000,000		10.46%	
ER-2010-0356					
GMO-L&P	June 25, 2011		$22,101,088		15.84%
GMO-MPS	June 25, 2011	$35,721,372		7.15%	
ER-2012-0024					
GMO-L&P	June 25, 2012		$11,756,893		7.27%
ER-2012-0175					
GMO-L&P	January 26, 2013		$21,696,437		12.74%
GMO-MPS	January 26, 2013	$26,245,608		4.86%	
Total 2007-2013		$155,220,634	$84,138,072	38.56%	76.73%
		Consolidated Rates			
ER-2016-0156	(Proposed)	$59,310,681	8.17%		
Approximate Residential Impact With Proposed				49.88%	91.17%

Staff Expert/Witness: Michael L. Stahlman

V. Rate of Return

A. Introduction

An essential ingredient of the cost-of-service ratemaking formula is the rate of return ("ROR"), which is usually premised on the goal of allowing a utility the opportunity to recover the costs required to secure debt and equity financing. If the allowed ROR is based on the costs to acquire capital, then it is synonymous with 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, David Murray, has estimated GMO cost of common equity by applying well-respected and widely-used methodologies to data derived from a carefully-assembled group of comparable companies. Staff also evaluated the relative change in the cost of common equity from a subset of Staff's proxy group from the 2014 electric rate cases for Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri"), The Empire District Electric Company ("Empire") and KCPL, Case Nos. ER-2014-0258, ER-2014-0351 and ER-2014-0370 respectively, to determine if market conditions have changed enough to warrant a change to the Commission's allowed return on common equity ("ROE") determinations of approximately 9.5% in 2014 for the Ameren Missouri and KCPL rate cases.[13] Staff believes the recent decline in interest rates accompanied by a significant increase in regulated utility stock prices justifies a reduction to the Commission's allowed ROEs of approximately 9.5%. Staff estimates the recent decline in the cost of equity justifies a reduction of allowed ROEs to a range of 8.65% to 9.35%, with a point recommended allowed ROE of 9.00%.

Staff recommends the Commission set GMO's allowed ROR based on the December 31, 2015, test year as follows:

Recommended Allowed Rate of Return as of December 31, 2015
for KCPL Greater Missouri Operations

			Allowed Rate of Return Using Common Equity Return of:		
Capital Component	Percentage of Capital	Embedded Cost	8.65%	**9.00%**	9.35%
Common Equity	49.01%	-----	4.24%	**4.41%**	4.58%
Preferred Equity	0.52%	4.29%	0.02%	**0.02%**	0.02%
Long-Term Debt	50.46%	5.41%	2.73%	**2.73%**	2.73%
Total	**100.00%**		6.99%	**7.16%**	7.34%

[13] The cost of common equity is the return required by investors, determined by expert analysis of market data relating to a carefully-constructed group of proxy companies. The allowed ROE, on the other hand, is the value selected by the Commission for use in calculating a utility's forward-looking rates for implementation at the end of the rate case.

Staff estimates that cost of common equity is in the range of 6% to 7%, but Staff has observed investors using costs of equity as low as in the 5% range to determine a fair price to pay for regulated utility stocks. Staff is not suggesting the Commission set GMO's allowed ROE to be on parity with the cost of equity. However, Staff's position is that because recent capital market information clearly suggests that the cost of equity is lower than it was in 2014, the Commission should reduce allowed ROEs. Staff is recommending that the Commission allow GMO an ROE that is 15 to 85 basis points lower than the 2014 allowed ROEs to allow ratepayers to share in the reduced cost of equity to GMO. This would result in an overall ROR of 6.99% to 7.34%, and a point recommendation of 7.16%. Staff recommends that the Commission authorize an ROE of 9.00% based on a reasonable reduced cost of equity of at least 50 basis points. The details of Staff's analysis and recommendations are presented in Schedules 1-16 in Appendix 2. Staff's workpapers will be provided to the parties at the time of filing Staff's Cost of Service Report. Staff will make any source documents of specific interest available upon the request of any party to this case or upon the Commission's request.

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 GMO 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 investment. The United States Supreme Court has described the minimum characteristics of a Constitutionally-acceptable rate of return in two frequently-cited cases.[14] In ***Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia***, the Court stated:[15]

> 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

[14] ***Federal Power Commission v. Hope Natural Gas Co.***, 320 U.S. 591, 64 S.Ct. 281, 88 L.Ed. 333 (1943); ***Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia***, 262 U.S. 679, *43 S.Ct. 675, 67 L.Ed. 1176* (1923).
[15] 262 U.S. at 692-693, 43 S.Ct. at 679, 67 L.Ed. at 1176, 1182-83.

> 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:[16]

> '[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.

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 that vary depending on market and business conditions.

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[16] 320 U.S. at 603, 64 S.Ct. at 288, 88 L.Ed. at 345.

The methodologies of financial analysis have advanced greatly since the *Bluefield* and *Hope* decisions.[17] Additionally, today's utilities compete for capital in a global market rather than a local market. 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 GMO's shareholders may expect is equal to that required for comparable-risk utility companies.

Financial theory holds that the company-specific Discounted Cash Flow ("DCF") method satisfies the constitutional principles inherent in estimating a return consistent with those of companies of comparable risk;[18] 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 GMO.

In this case, Staff has applied this comparable company approach through the use of both the DCF method 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***. However, as Staff will discuss extensively throughout this section of the report, Staff believes it has been common practice for commissions to allow returns on equity that are higher than the

[17] Neither the Discounted Cash Flow ("DCF") nor the Capital Asset Pricing Model ("CAPM") methods were in use when those decisions were issued.
[18] 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*.

costs of equity for utilities due to a very low cost of capital environment. Consequently, Staff's recommended allowed ROE is higher than Staff's estimate of GMO's cost of equity.

Because the Commission authorized ROEs in 2015 for Missouri's major electric utilities that it deemed to be fair and reasonable based on capital market evidence from the fall of 2014 to early 2015, Staff believes it can best serve the Commission by providing it an estimate of the relative change in electric utilities' cost of equity in general, and GMO's in particular, as compared to that period. Staff believes the cost of equity is 50 basis points lower now as compared to that period. Consequently, Staff recommends the Commission allow GMO an ROE in a range of 8.65 to 9.35 percent with a point recommended allowed ROE of 9.00 percent.

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 economy continues to grow, but at an anemic pace. Real Gross Domestic Product ("GDP") increased by 1.1% in the first quarter after increasing by 1.4% in the fourth quarter of 2015.[19] Real GDP increased by 2.4% for the entire 2015 calendar year. As of June 2016, the Federal Reserve Board Members and the Federal Reserve Bank Presidents projected real GDP would grow in the range of 1.8% to 2.2% in 2016; 1.6% to 2.4% in 2017; and 1.5% to 2.2% in 2018. The longer run projections for real GDP growth were between 1.6% and 2.4%.[20]

As recently as the Federal Open Market Committee ("FOMC") meeting in December 2015, the FOMC indicated that it expected to increase the Fed Funds rate four times in quarter-percentage point increments by the end of 2016. However, now it is looking likely that the most the Fed may increase the Fed Funds rate is 0.50% with a greater number of officials

[19] http://www.bea.gov/newsreleases/national/gdp/gdpnewsrelease.htm "Real" GDP is adjusted to reflect inflation.
[20] http://www federalreserve.gov/monetarypolicy/files/fomcprojtabl20160615.pdf.

indicating one rate hike of 0.25% is more likely than two by the end of the year.[21] In fact, the FOMC seems to be leaning toward the notion that the U.S. economy may be secularly stagnant, meaning that the lower interest rates are consistent with lower productivity growth rather than suppressed by the Fed's monetary policy strategy. The following is an excerpt from the *WSJ* article discussing this notion:

> Fed officials have been weighing whether the economy's equilibrium interest rate – a rate at which the economy is in balance, growing with stable inflation and low unemployment – has fallen because of long- running trends holding back growth and beyond the Feds' control, such as the retirement of older workers and low productivity growth.[22]

Consequently, it seems as if the low interest rate environment may be more permanent than the Fed and the market had initially thought was likely. This situation is not limited to the United States as many developed countries throughout the world are experiencing extremely low long-term interest rates with some countries actually experiencing negative long-term rates. The longer the United States and the world stay in a lower interest rate pattern, the higher the demand will be for interest-rate sensitive securities, such as utility stocks and bonds, which results in lower costs of capital.

2. Capital Market Conditions

a. Utility Debt Markets

Utility debt markets currently indicate a lower cost-of-capital environment than that which existed during the fall of 2014 (Staff used bond yield data through October 31, 2014, to support its recommendations to the Commission in the 2014 electric rate cases that it lower allowed ROEs at that time). However, current utility debt yields have not reached the lows achieved during the first few months in 2015. If one were to assume that the risk premium[23] required for investing in utility stocks rather than utility bonds was constant, then a change in utility debt yields corresponds to a one-for-one change in required returns on equity as well. Although it is unlikely that the change in utilities' costs of equity will be perfectly correlated to changes in utility debt yields, it is widely recognized in the investment community that regulated

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[21] Jon Hilsenrath and Kate Davidson, "Wary Fed Rethinks Pace of Hikes." June 16, 2016, *Wall Street Journal*, pp. A1 - A2.
[22] *Id.*, p. A-2.
[23] Risk Premium in this context is the excess required return to invest in a company's equity rather than its debt.

utility stocks are a close alternative to bond investments, and therefore, they are highly correlated over time.

Although the Moody's 'Baa' (equivalent to a 'BBB' S&P rating) public utility bond index implied an increase in utility bond costs at the beginning of this year, Staff recently discovered that many of the bonds that made up this index were issued by companies that were more accurately classified as energy companies. Staff discovered that as of September 30, 2015, nine of the eighteen companies in the 'Baa' public utility bond index had significant commodity exposure. Most energy companies' securities incurred significant declines in value early this year, but the same was not true for traditional regulated utility companies. Although 'A' rated utilities did have slightly increased yields in late 2015 and early 2016, they dropped below 4% in May 2016, which hadn't occurred since the significant rally in utility bond prices from December 2014 through the first few months of 2015, which resulted in utility companies' stock prices rallying significantly as well.

Notwithstanding Staff's above concerns about the constituents in the Moody's public utility bond index, the average utility bond yield based on the Moody's public utility bond index for the most recent 3 months in 2016 was 4.05%. This compares to the average of approximately 4.35% during the third quarter of 2014 and 4.24% during the fourth quarter of 2014 (*see* Schedules 4-1 and 4-3). Consequently, comparing recent average utility bond yields to those Staff used when quantifying its recommended allowed ROEs in the 2014 rate cases, indicates an average decline of 20 to 30 basis points.

As Staff discussed in the recent Missouri-American Water Company and The Empire District Electric Company rate cases, Case Nos. WR-2015-0301 and ER-2016-0023, respectively, the spread between Moody's A-rated utility bonds and Baa-rated utility bond index increased significantly in late 2015 and early 2016. This is shown in the attached Schedule 4-5.

For the most recent three months the average spread between 30-year T-bonds (2.57%) and average utility bond yields (4.05%) was 148 basis points. For the 3 months through September 2014, the average spread between 30-year T-bonds (3.26%) and average utility bond yields (4.35%) was 109 basis points. The increase in the spread is explained mainly by the significant decline in 30-year T-bond yields, but more modest decline in utility bond yields (*see* Schedules 4-3 and 4-4). Consequently, utility bond yields have shown some resistance to declining as significantly as Treasury rates. However, as Staff will explain in the following discussion about utility equity markets, the decline in Treasury rates has had a dramatic impact on valuation levels of utility stocks, causing Staff to conclude that the cost of equity for utility companies has declined by more than utility bond costs.

b. Utility Equity Markets

For the twelve months ending June 30, 2016, the total return on the Standard & Poor's 500 ("S&P 500") was 3.99%, the total return on the Edison Electric Institute ("EEI") Index of electric utilities was 33.42% (33.77% if companies with pending merger and acquisition activity are excluded) and the total return for EEI's Regulated electric utilities was 37.53% (39.60% if companies with pending merger and acquisition activities are excluded).

Traditionally, over long-term market periods, the total returns on the S&P 500 are expected to be greater than total returns on utility stocks because the S&P 500 is expected to grow at a higher rate than that of utilities and investors in the S&P 500 incur greater risk than that of utility stocks. This expectation is supported by a common portfolio statistical measure referred to as the beta of the stock which measures the covariance of a portfolio or asset as compared to the variance of that asset or portfolio. Betas for regulated utility portfolios have consistently measured in the .60 to .80 range over long periods of time, with most regulated utilities typically having betas of around 0.7. This measurement simply means that utility stocks should lag the S&P 500 in both gains and losses as the market moves up or down. However, in recent years utility stocks have actually experienced significant outperformance over the S&P 500, which can largely be attributed to the slow growth, low long-term interest rate environment. At the time of GMO's last rate case, utility stocks had rallied significantly enough that even the Public Counsel's witness was recommending an upward adjustment to his cost of common equity estimates because he believed the lower dividend yields were anomalous and would return to levels more typical of a higher interest rate environment. Although interest rates did increase for a few months during the middle to the end of 2015, they have since started to return levels that were experienced in late 2014 and early 2015, which again is causing utility stocks to significantly outperform the broader markets.

An insightful analysis to determine whether utility stock investors are requiring different returns than they were in late 2014 and early 2015 is to simply measure total returns since the 2014 rate cases and compare these to the broader markets over the same period. Because Staff used stock market data through the fall of 2014 to quantify the decline in the cost of equity of

25 to 75 basis points for the 2014 electric cases, Staff analyzed stock returns for the period September 30, 2014, through June 30, 2016, to determine whether utility stock investors have changed their return requirements. For this period EEI's Regulated electric utility index[24] had a total return 45.05%. This compared to a total return of 10.47% for S&P 500 for the same period. The companies in Staff's current proxy group that were also in Staff's 2014 refined proxy group,[25] had a total return of 45.05%. This translates into an annual compound total return of 23.68%. The bidding up of utility stock returns since September 30, 2014, supports a reduction to electric utilities' allowed ROEs because the primary driver of the higher returns for utility stocks are macroeconomic factors, not higher expected industry growth. EEI's commentary is consistent with this view. EEI stated the following in its 2015 fourth quarter utility stock analysis:

> The trend that has shaped utility share performance relative to the broad market for six years seems likely to continue: it will be tied less to slow-changing industry business fundamentals than faster-changing macroeconomic developments, whether relating to economic data, interest rates, oil prices, and other macro or geopolitical events that spur bullish or bearish market moves.[26]

Many utility equity analysts during the past few years have consistently discussed the premium at which regulated utility stocks have traded as compared to the S&P 500, which is not typical over the long-term in capital markets. Typically, due to the low-growth and high-dividend yield characteristics of utility stocks, the price-to-earnings ratios are lower for utility stocks as compared to the higher-growth, lower-yield profile of the S&P 500. Equity analysts consistently explain that the higher multiples are driven by the low interest rate environment, not higher growth expectations for the regulated utility industry as compared to the broader markets.

Goldman Sachs' analysis consistently shows that utilities typically trade at a premium to the market when U.S. 10-year treasury yields trade below the 3% level and trade at a discount to the market when U.S. 10-year treasury yields trade above 3%. The 10-year Treasury yield has been trading at almost half this level recently with recent monthly averages being in the

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[24] Excluded the following companies due to pending merger and acquisition activity: Duke Energy Corporation, Empire District Electric Company, Great Plains Energy, Southern Company, TECO Energy, Westar Energy

[25] Excluded OGE Energy due to midstream operations.

[26] "Stock Performance: Q4 2015 Financial Update, Quarterly Report of the U.S. Shareholder-Owned Electric Utility Industry," Edison Electric Institute.

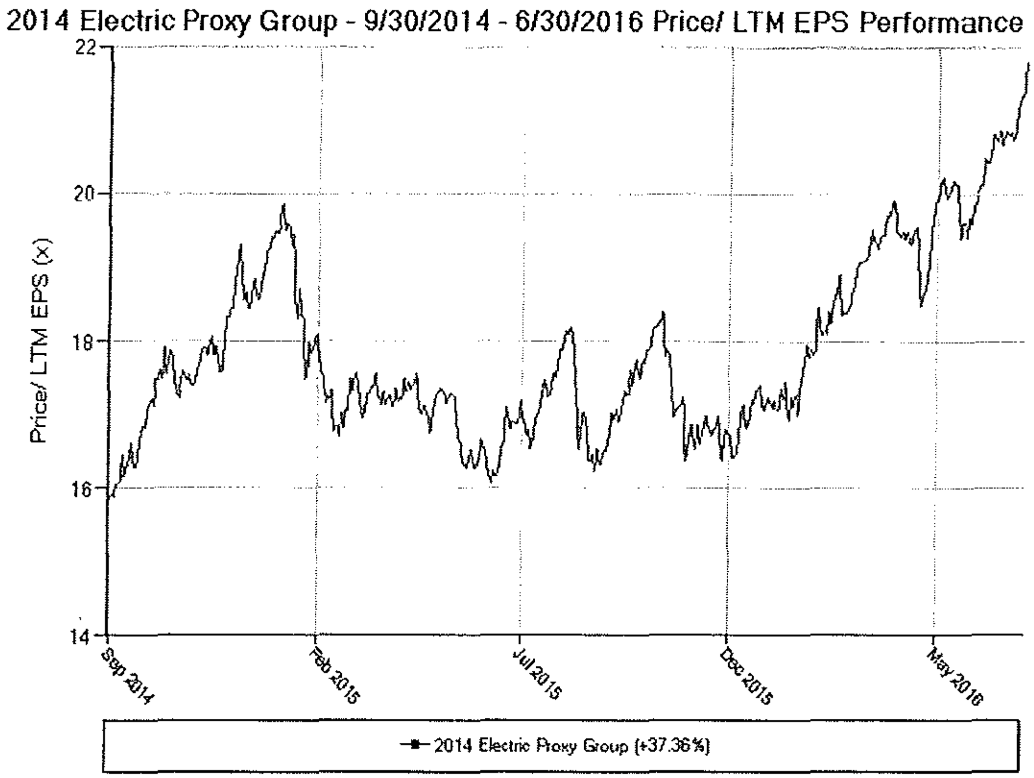
1.6% to 1.8% range.[27] Coupling the fact that utilities are trading at a premium to the S&P 500 even though utilities have lower long-term growth expectations than the S&P 500, clearly indicates that utilities' cost of equity continues to be quite low in the current economic and capital market environment. Because valuation levels for utility stocks are even higher in 2016 than they were at the end of 2014 and in early 2015, it is reasonable to conclude that the cost of equity for utility companies is lower and therefore the allowed ROEs should be lower.

In order to be able to ensure that the high returns for the regulated utility industry since September 30, 2014, are explained by a reduction in the required returns for utility stocks rather than unexpected growth of the electric utility industry, one can simply compare actual per share results versus expected per share results at the time of the 2014 rate case. Staff found that 5 of the 9 companies had actual 2014 EPS results that were the same or less than expectations around the fall of 2014. In 2015, 6 of the 9 companies had actual EPS results that were less than expectations in 2014. In addition, the expected 5-year CAGR in EPS is lower in 2016 than it was in 2014. All of these industry and company-specific factors should cause returns to be lower than expected in 2014, but returns were actually higher than expected. This information supports Staff's conclusion the explanation for the increase in electric utility stock prices is a decline in investors' required returns on equity, i.e. the cost of common equity.

A contraction in the required ROE, i.e. the cost of equity, allows for an expansion in the price-to-earnings (p/e) multiples of the sector. As indicated above, one of the other primary reasons the p/e ratio would increase is because of an increase in expected growth for the sector, but as Staff discovered, the expected long-term growth in EPS has actually declined since 2014. Consequently, to the extent that there has been an additional expansion in p/e ratios since 2014, it is explained by the continued decline in the cost of equity.

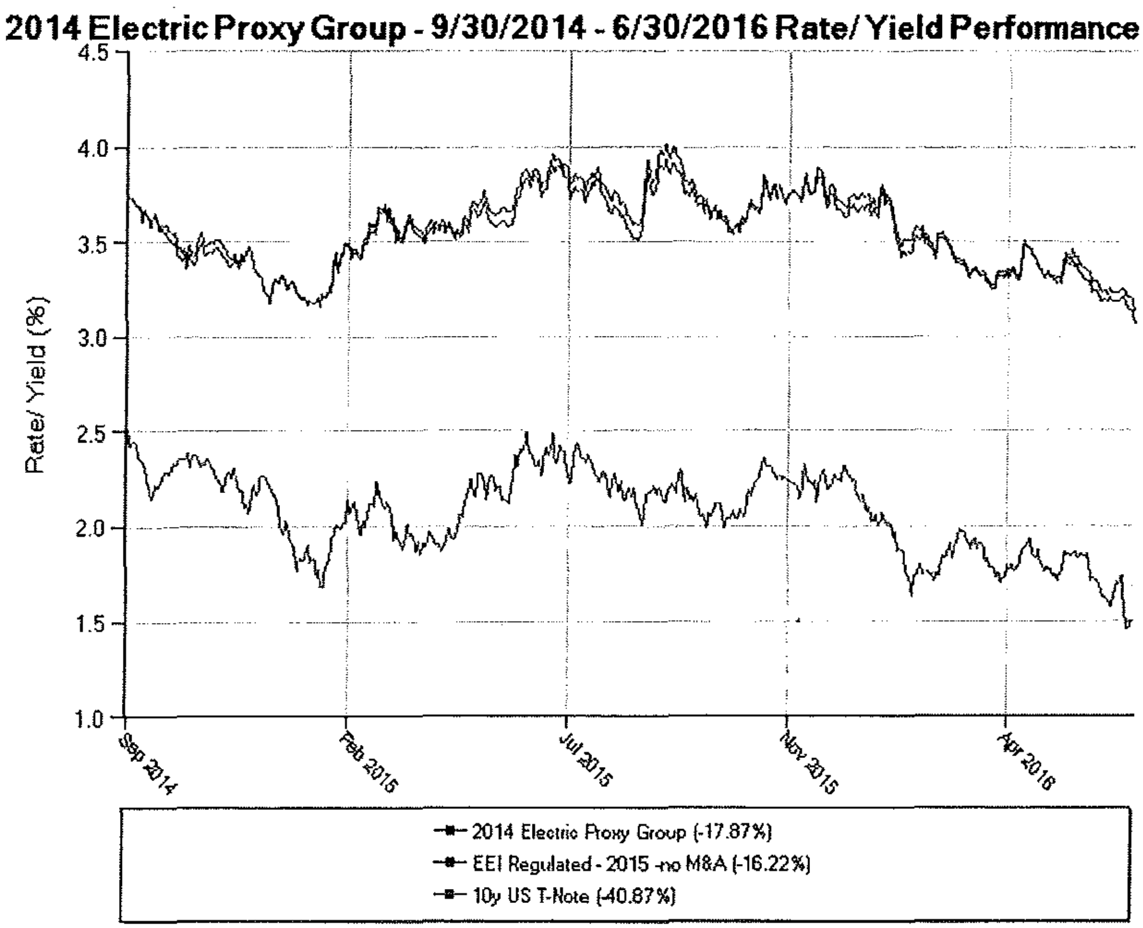
Below is a graph of the change in the price-to-last-twelve-months'-earnings ratios ("p/e ratios") for the nine companies from Staff's 2014 proxy group for the period September 30, 2014, through June 30, 2016. Staff selected September 30, 2014, as the starting point because this within the period Staff used in the 2014 rate cases to quantify the 25 to 75 basis point decline in the cost of equity at that time.

[27] https://fred.stlouisfed.org/series/GS10.



As can be seen, the p/e ratios have now exceeded the high levels experienced at the beginning of the 2015. As the record shows from the 2014 rate cases, some rate of return witnesses, including the Public Counsel witness, feared that these higher valuation levels were not sustainable, causing them to resist the lower results obtained from objective analyses. The fact that the markets have reached and surpassed these high valuation levels once again is just further proof that the Commission should not consider these market signals as anomalous, but rather likely to continue into the foreseeable future. Considering that the Fed seems to be convinced that lower long-term rates are more a function of the market's expectations of a low-growth U.S. economy, it is entirely reasonable to expect that low long-term rates will continue for the foreseeable future. In fact, at the time Staff was writing this testimony, 10-year Treasury yields were at approximately 1.4%. These lower rates have clearly influenced the valuation levels of utility stocks.

Although Staff did not discover any earnings revisions that would skew the price to historical EPS ratios it analyzed in the graph above, it is important to analyze any changes in the price to forward earnings ratios since these are the multiples most often discussed by investment analysts. Staff also decided to analyze the changes in the price-to-forward EPS multiples, as reported by FactSet,[28] because these multiples are often discussed by equity analysts and investors when evaluating whether a stock is attractively valued (lower p/e ratio than implied in their valuations). In 2014 the average p/e ratio for Staff's 2004 electric utility proxy group was 18.7x; in 2015 it was 18.4x and in 2016 it increased to 20.4x. Therefore, the p/e ratios based on projected earnings corroborate the information conveyed by the increased in p/e ratios based on historical earnings. The increase in utilities' p/e ratios is consistent with their historical high correlation with 10-yeat Treasury yields. As 10-year Treasury yields fall, utility valuation levels increase. This can also be observed through the positive correlation of the electric utility industry's dividend yields to that of 10-year Treasury's in the following graph:



[28] Staff receives FactSet compilation of equity analyst estimates through its subscription to SNL Financial.

The top two lines show changes in the dividend yields for Staff's 2014 electric proxy group and EEI's Regulated electric utilities. The bottom line shows the changes in the 10-year Treasury yield. As can be seen, the dividend yields on both electric utility groups have declined consistent with the recent decline in 10-year Treasury's. If 10-year Treasury's remain at the current historically low levels, it would seem that electric utility stock prices can be sustained at their current higher valuation levels. These valuation levels are actually higher than they were in early 2015 when many rate of return witnesses in the 2014 electric rate cases claimed that these valuation levels were not sustainable and utility dividend yields were likely to increase again. While it is true dividend yields did increase for a few months following the 2014 rate cases, it is becoming more accepted by the investment community that low economic growth and low long-term interest rates may be the new normal. For example, UBS stated the following in a research report published on June 27, 2016:

> **Utilities hitting relative highs but sector stays favored post UK vote to leave** Utilities are trading at an absolute high forward P/E (18.7x) and are trading at a 21% premium to the S&P 500, tied for the highest premium since July 2012 on a relative basis. For context when utilities were last at this relative level the US 10Yr treasury was yielding 1.47% vs 1.56% today. In each of 2011, 2012, & 2013 utilities tested their ~20% premium versus the broader market and subsequently declined towards a 5% average premium but we think 2016 could be different. For context in November 2008 at the peak of the financial crisis the premium was 32%. The continued outperformance of utilities is not surprising given declining US and ever more importantly global interest rates and while we would ordinarily say that the relative upside/downside appears less attractive at these levels given the sector's slowing EPS growth, the UK vote to leave suggests defensive sectors will remain well supported, pending increased political uncertainty. For example, both US treasuries and global benchmarks have retraced lows which still makes the 3.1% average utility yield appear attractive. Bottom line, we believe that between substantial European uncertainty, continued declines in global interest rates, and a lack of clarity on the US economic/political situation, we see the combination of events could drive the utilities sector even higher.[29]

[29] Julien Dumoulin-Smith, Paul Zimbardo, Jerimiah Booream, "US Electric Utilities & IPPs: *Is the Rally Running Out of Gas?*," June 27, 2016, UBS Securities, LLC.

Not only are publicly-traded stock prices being bid-up due to the low cost of capital environment, but this is also one of the primary drivers supporting significant acquisition premiums being offered in much of the current merger and acquisition activity. Many of the proposed acquisitions, including those involving Missouri utility properties, are being financed with low cost debt at the holding company level. Because many of the acquirers assume that the target companies will continue to earn rates of return based on subsidiary-specific allowed rates of return, the acquirers believe they can create value for their own shareholders by earning a margin over the cost of capital incurred to acquire these entities. The fact that higher valuations are being driven by lower capital costs supports the lowering of allowed returns. Investors are indicating that they are willing to pay a high price for the current cash flow stream from utilities because their required return is lower than what is factored into ratemaking.

Additionally, the following observations were provided in a *WSJ* article published on July 7, 2016 that discussed the significant increase in utility stock prices:

> The biggest driver of the good times at utilities is low interest rates. The most obvious impact has been yield-chasing investors driving up share prices and pushing valuations for the world's stodgiest industry to the highest level in at least 20 years, according to FactSet. Utilities don't look so expensive when compared with Treasury yields. The spread between dividend yields on utilities and 10-year Treasurys is nearly 2 percentage points, among the widest ever.
>
> Low rates also have boosted utilities' profits. That is because regulators allow utilities to make a specific return on their investments. Utilities borrow a lot, so rates matter. But regulators have lagged behind the reality. So rates are being set as if utilities were borrowing at higher rates than they really are. The difference is profit.
>
> The second benefit for the industry has been lower energy prices. Energy accounts for roughly two-thirds of consumers' electric bills, and utilities just pass along those costs. But when utility bills are low overall, regulators are more likely to be generous when they negotiate rate increases, according to Morningstar utilities analyst Travis Miller.

> Finally, there is the benefit of having more-valuable shares, which makes it cheaper to raise capital. "Your cost of equity has gone down and your cost of debt has gone down," Mr. Miller said.[30]

As Staff will discuss later in this section of the Staff Report, if interest rates remain low, investment analysts expect that regulators will eventually catch up to the market and start lowering authorized ROEs to reduce the spread between allowed ROEs and the market's cost of equity.

D. GPE's, KCPL's and GMO's Operations

The following excerpts from a combined, GPE and KCPL, Form 10-K filing with the United States Securities and Exchange Commission ("SEC") for the 2015 calendar year, provides a good description of GPE's current business operations and current organizational structure:

> Great Plains Energy, a Missouri corporation incorporated in 2001 and headquartered in Kansas City, Missouri, is a public utility holding company and does not own or operate any significant assets other than the stock of its subsidiaries. Great Plains Energy's wholly owned direct subsidiaries with operations or active subsidiaries are as follows:
>
> • KCP&L is an integrated, regulated electric utility that provides electricity to customers primarily in the states of Missouri and Kansas. KCP&L has one active wholly owned subsidiary, Kansas City Power & Light Receivables Company (KCP&L Receivables Company).
>
> • GMO is an integrated, regulated electric utility that provides electricity to customers in the state of Missouri. GMO also provides regulated steam service to certain customers in the St. Joseph, Missouri area. GMO has two active wholly owned subsidiaries, GMO Receivables Company and MPS Merchant Services, Inc. (MPS Merchant). MPS Merchant has certain long-term natural gas contracts remaining from its former non-regulated trading operations.

[30] Ken Brown, "Be Careful: Utilities Are Riskier Than They Look," July 7, 2016, Wall Street Journal, pp. C1 and C4.

E. KCPL, GPE and GMO Credit Ratings

1. Credit Ratings

GMO, KCPL and GPE are currently rated by Moody's and Standard & Poor's ("S&P"). It is important to understand the current credit standing of the various entities, as these ratings influence investors' views of the risk associated with investing in GMO. Although Staff is not estimating the cost of capital for KCPL and/or GPE in this case, the influence of these entities' risks on GMO must be understood in order to estimate a fair rate of return for GMO.

GMO's Moody's senior unsecured credit rating is 'Baa2' and its S&P senior unsecured credit rating is 'BBB+.' GMO's S&P rating is considered to be one notch stronger than the Moody's rating. GPE's Moody's senior unsecured rating is the same as GMO's, 'Baa2.' KCPL's S&P senior unsecured rating is the same as GMO's, but GPE's is one notch lower because S&P's methodology requires a one notch differential between the subsidiary and the parent company. KCPL's Moody's rating is one notch stronger than both GPE's and GMO's.

GPE's 2015 SEC Form 10-K Filing indicates that GPE has guaranteed some of GMO's long-term debt and short-term debt, which includes GMO's commercial paper program. This is noteworthy considering the fact that the only other asset GPE owns is KCPL. Consequently, GMO's credit standing is indirectly supported by KCPL's credit quality, which KCPL ratepayers supported during the comprehensive energy plan by paying higher rates than normally would have been allowed under traditional cost of service ratemaking. It wasn't until GPE provided an unconditional guarantee to GMO' short-term credit that GMO was able to access the commercial paper markets, which occurred in November 2011.

It is important to understand that S&P and Moody's have some methodological differences that can cause differences in their views on credit ratings. One key difference between S&P and Moody's 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 tends to give at least some weight to the stand-alone subsidiary risk profile in rating the subsidiary's credit risk.

The following is an excerpt from a June 17, 2016, S&P credit-rating report on GMO:

> Our outlook on GMO reflects that on parent Great Plains Energy Inc. (GPE). The negative outlook on GPE and its subsidiaries reflects the potential for lower ratings if GPE's financial risk profile, which will deteriorate due to the financing used in the

> Westar Energy Inc. acquisition, does not improve after the transaction closes such that funds from operations (FFO) to total debt is well over 13% after 2018.

In its June 2, 2016, Credit Opinion on GMO, Moody's provided the following "Summary Rating Rationale" in its comments:

> KCP&L Greater Missouri Operation Company's (GMO) Baa2 senior unsecured rating reflects its fully regulated vertically integrated utility operations in Missouri with relatively predictable cash flow and earnings. It also incorporates our expectation that GMO will maintain stable key financial metrics similar to the current level and that the overall regulatory environment in Missouri will remain consistent.

Although S&P has put GMO's credit rating on a "negative outlook" due to GPE's announcement of its intent to acquire Westar Energy, Moody's decided to affirm GMO's credit rating and its "stable outlook." Moody's did place GPE's ratings on review for a possible downgrade due to "the additional leverage and new capital structure complexity reducing financial flexibility across the entire corporate family." GPE's proposed acquisition of Westar would result in GPE carrying a much higher amount of debt as a percentage of the consolidated debt of its subsidiaries (from 2% to 35% of the total consolidated debt). Despite Moody's decision to affirm GMO's credit rating, it did cite GPE's levered acquisition of Westar Energy as an area of concern that would constrain GMO's ratings. Consequently, even though Moody's tends to give more weight to subsidiary-specific business risk and financial risk than S&P, Moody's also gives consideration to the activities of GPE.

Because Staff's allowed rate of return information is based on GPE's consolidated capital structure and embedded costs of capital as of the updated test year, December 31, 2015, which is before GPE announced its intent to acquire Westar Energy on May 31, 2016, Staff's rate of return recommendation is not impacted by financial concerns or capital market reactions due to the announcement of the proposed transaction. Staff will need to evaluate any potential financial effects of the proposed acquisition of Westar Energy on GPE and/or GMO for purposes of deciding whether the capital structure and embedded costs of capital through the true-up period have caused any increased capital costs.

F. Cost of Capital

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

1. Capital Structure

Staff recommends the use of GPE's consolidated capital structure as it is consistent with the capital structure ordered in the last KCPL rate case (Case No. ER-2014-0370)[31] and the last GMO rate case (Case No. ER-2012-0175).[32] Schedule 7 presents GPE's consolidated capital structure and associated capital ratios as of the update period (December 31, 2015) –49.01% common equity, 0.52% preferred equity and 50.46% long-term debt.[33]

2. Embedded Cost of Debt and Preferred Stock

Staff recommends the use of GPE's consolidated embedded cost of debt and preferred stock as it is consistent with the embedded cost of debt and preferred stock ordered in the last KCPL rate case (Case No. ER-2014-0370) and the last GMO rate case (Case No. ER-2012-0175). Schedule 6-1 presents GPE's consolidated embedded cost debt of 5.41% as of December 31, 2015 and Schedule 6-2 presents GPE's consolidated embedded cost of preferred stock of 4.29% as of the update period.

3. Cost of Common Equity

Staff estimated GMO's cost of common equity by analyzing cost of common equity indications from three proxy groups. The first proxy group was selected by applying several screening criteria to recent financial metrics (*see* Schedule 8). Staff's second proxy group was simply a subset of companies from the first proxy group that had little to no exposure to any non-regulated business risks. The third proxy group was based on companies that overlapped Staff's refined proxy group from the 2014 electric rate cases in which the Commission determined that an approximate 9.5% allowed ROE was reasonable. While Staff continues to estimate a much lower cost of common equity than the average allowed ROEs around the country, Staff's

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[31] ER-2014-0370, Report and Order, Issued Date: September 2, 2014 and Effective Date: September 15, 2014.
[32] ER-2012-0175, Report and Order, Issue and Effective Date: January 9, 2013.
[33] Response to Staff's Data Request No. 0120.

recommended allowed ROE is based on Staff's quantification of the relative change in the cost of equity since the Commission last made determinations on allowed ROEs for its regulated electric utilities. Staff used a CAPM analysis and a survey of other indicators as a check of the reasonableness of its recommendations.

a. The Proxy Groups

Although Staff applied the same selection criteria it used in recent electric rate cases to select an initial proxy group, Staff also chose a couple of subsets of companies from this proxy group to provide insight on the relative change in the cost of common equity compared to late 2014 and early 2015, which was the period evaluated when the Commission last made allowed ROE determinations for its Missouri electric utilities. The only changes Staff made to the refined proxy group from the 2014 rate cases was to exclude Great Plains Energy, Southern Company and Westar Energy due to the fact that each of these companies have merger and acquisition transactions pending. Staff will first explain how it selected the new proxy group and provide cost of common equity indications from this proxy group. Staff will then discuss how it determined which companies within the broader proxy group are appropriately considered pure-play regulated utility companies. Finally, Staff will specifically identify the overlapping companies from the 2014 electric cases that Staff used to gain specific insight on valuation and cost of capital changes compared to late 2014.

Starting with 64 market-traded companies classified as power companies by SNL Financial, Staff applied a number of criteria to develop a proxy group comparable in risk to GMO's regulated electric utility operations (*see* Schedule 8). Staff's criteria are designed to capture companies with primarily regulated electric operations (which means the companies' operations may have other regulated operations, such as gas distribution), and whose electric utility operations contain a significant amount of generation assets. Staff believes the criteria it selected accomplished this objective. However, Staff notes that even with its screening criteria, some of the companies it chose for its proxy group have business segments other than rate-regulated utility operations that cause volatility in the contribution of the regulated utility operations to the percentage of income on a year-to-year basis. That being said, Staff will refine its broader proxy group to eliminate additional companies that have significant non-regulated business operations causing volatility in year-to-year contributions to consolidated income. Staff will show the results of the broader proxy group, the pure-play proxy group, and the 2014 refined proxy group in each of its schedules. Staff's criteria are as follows:

1. Classified as a power company by SNL (64 companies);

2. Publicly-traded stock (no companies eliminated, 64 remaining);

3. Followed by EEI and classified by EEI as a regulated utility (32 companies eliminated, 32 remaining);

4. At least 50% of plant from electric utility operations (4 companies eliminated, 28 remaining);

5. At least 25% of electric plant from generation (5 companies eliminated, 23 remaining);

6. At least 80% of income from regulated utility operations (1 company eliminated, 22 remaining);

7. No reduced dividend since 2013 (0 companies eliminated, 22 remaining);

8. At least investment grade credit rating (0 companies eliminated, 22 remaining);

9. At least 2 equity analysts providing long-term growth projections in the last 90 days (4 companies eliminated, 18 remaining);

10. No pending merger or acquisition announced recently (5 companies eliminated, 13 remaining).

The resulting final group of 13 publicly-traded electric utility companies ("the comparables") was used as the broad proxy group to estimate a cost of common equity for the electric utility industry. These companies are shown on Schedule 9.

The final criterion used to eliminate any remaining companies that may have segments that have risks inconsistent with a regulated utility is criterion No. 6. In order to select companies that consistently received at least 80% of their income from rate-regulated utility operations, one has to review past performance (Staff chose the last 3 years). However, limiting the selection criteria to just looking at the average amount of income from regulated utility operations can cause the selection of companies that have material volatility in the percentage of income contributed by the regulated utility operations simply because a non-regulated segment may contribute 25% to margin in one year and then reduce margin by 10% in the following year. In the latter situation, one would erroneously conclude that the risk profile of the company is consistent with a regulated utility since the regulated income was over 100% of the company's income. If one were to take a simple average of these two years, then the company would be selected as a comparable company based simply on the fact that 92.5% of the average income came from regulated utility operations. Being that the non-regulated operations significantly increased the variability of income, it is important to add an additional criterion to eliminate companies that have such volatile segments.

Consequently, Staff decided to research the business segment financial data of its broad proxy group in further detail to determine which of the remaining companies have material contributions from business segments that are not consistent with a pure-play regulated company profile. Of course, each of these companies has varying degrees of non-regulated business exposure and some of the non-regulated operations cause more volatility in income than others. Staff noticed that OGE Energy, Black Hills Corporation and PNM Resources have equity betas that are much higher than the average of around 0.7, which would seem to indicate that these are not pure-play regulated utility companies. After looking at the details of these companies' business segment data, Staff discovered that OGE Energy has significant exposure to natural gas midstream operations through its investment in Enable Midstream Partners. Consequently, OGE Energy's risk profile is not consistent with a pure-play regulated utility. Upon further investigation, Black Hills Corporation has had significant contributions from its non-regulated Power Generation segment, its Coal Mining segment and it Oil and Gas segment. These segments have contributed to Black Hills' risk profile, but due to their underperformance, the regulated utility operations have contributed more than 80% to its overall income. However, PNM Resources' current operations are consistent with a pure-play regulated utility. Therefore, Staff kept this company in the pure-play proxy group. Entergy is another company that had significant exposure to non-regulated operations through its Wholesale Commodities segment. Although DTE Energy Company and American Electric Power are less of a concern to Staff as to the effect the non-regulated activities have had on the stock's volatility as it relates to a pure-play risk profile, these companies should also be eliminated due to significant contributions from non-regulated operations. For purposes of comparison to the broad proxy group, Staff excluded the aforementioned five companies from the broad proxy group to determine if this had a material effect on Staff's cost of capital estimates and conclusions.

b. The Constant-growth DCF

Next, Staff estimated GMO's cost of common equity applying values derived from the proxy groups 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.[34] 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_0 is the current price of the stock; and

g is the dividend growth rate.

The term D1/P0, 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 2016 fiscal year and 2017 fiscal year FactSet projected dividends per share (*see* Schedule 11) by the average daily closing stock prices for the three months ending June 30, 2016 (*see* Schedule 11).[35] Staff weighted the FactSet projections in this manner in order to reflect the approximate amount of time remaining in the 2016 fiscal year for each comparable company. Staff used the above-described stock price because it reflects current market expectations. The projected average dividend yield for the broader proxy group of thirteen comparable companies is approximately 3.42%. The projected average dividend yield for the pure-play proxy group of eight comparable companies is also

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

[35] The averaging technique minimizes the effects of short-term stock market volatility on the calculation of dividend yield. P0 is calculated by calculating the average of daily closing prices over the selected period.

approximately 3.29%. The projected average dividend yield for the 2014 refined proxy group was 3.31%. Although the proxy groups that are more regulated in nature imply the use of a lower dividend yield, Staff chose to give consideration to the broad proxy group in selecting a 3.35% dividend yield.

i. 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 the actual dividends per share ("DPS"), 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 quite volatile, at least for a few of the companies in the proxy group.[36] Staff also reviewed equity analysts' consensus estimates for long-term compound annual growth rates as reported by FactSet and provided by SNL Financial. The average consensus long-term growth rates for the broad proxy group is currently 5.21%, 5.96% for the pure-play proxy group and 5.76% for the 2014 refined proxy group (*see* Schedule 10-6).

Based on the shorter-term projected EPS growth rate data, one may argue that electric utilities can grow at a rate of 5 to 6 percent, but it would be unreasonable to conclude that this growth rate is sustainable in perpetuity because it does not give consideration to empirical and logical information that suggests that utility companies should grow at a rate less than that of the overall economy due to the mere fact that investors invest in utility companies for yield and not growth. In fact, considering that companies in the S&P 500 (a proxy for the U.S. capital markets) in recent years have retained approximately 65% to 70% of their earnings for reinvestment,[37] while electric utilities' retention ratio has been less than half that of the S&P 500,[38] it makes logical sense that utilities will grow at a rate less than that of nominal GDP growth. Consequently, a projected long-term, steady-state nominal GDP growth rate[39] should be considered as an upper constraint when testing the reasonableness of growth rates used to

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[36] Schedule 10-4 depicts the annual compound growth rates for DPS, EPS and BVPS for each comparable company for the past ten years. Schedule 10-3 lists the annual compound growth rates for DPS, EPS and BVPS for each of the comparable companies for the past five years.

[37] Table B-95 and B-96 attached to the *2013 Economic Report of the President.*

[38] http://www.wyattresearch.com/article/dividend-payout-ratio.

[39] The nominal GDP growth rate, contrasted to the real GDP growth rate introduced earlier, is not adjusted for inflation.

estimate the cost of equity for a regulated electric utility. Staff will provide more detail on economic growth projections when discussing the multi-stage DCF, but a high-end estimate for nominal GDP is not much higher than 4.3%, causing an estimated constant growth rate over this rate to be highly suspect.

Because Staff is not relying on the constant-growth DCF to quantify the change in the cost of equity since the 2014 rate cases, Staff's range of growth rate estimates for the constant growth DCF is fairly wide, but limited by common sense restraints on sustainable growth rates, actual experienced growth rates for the electric utility industry and also Staff's understanding of how investment analysts apply DCF analyses in practice. Several companies in Staff's proxy group have projected 5-year CAGR in EPS that simply are not sustainable in the long-term. Considering that actual long-term growth experience in the electric utility industry barely supports a constant growth rate much more than 3%, Staff will use 3.0% as the low end and 5.0% for the high end investors' expectations of a constant growth rate.

Using the growth rate range Staff established for the constant-growth DCF results in a cost of equity estimate of 6.35% to 8.35%. However, Staff will again rely on its multi-stage DCF analysis to provide what it believes to be a more reliable cost of common equity due to the non-sustainable growth rates of a few companies in its proxy group.

c. The Multi-stage DCF

i. Overview

The constant-growth DCF model may not yield reliable results if industry and/or economic circumstances cause expected near-term growth rates to be inconsistent with sustainable perpetual growth rates.[40] Consequently, as in the last rate case, Staff again performed a multi-stage DCF analysis in this case and is relying primarily on this analysis to draw conclusions on the change in the cost of common equity since the last rate case because the multi-stage DCF is dynamic enough to consider changes in near-term growth rates, but still maintain a consistent perpetual growth rate as this rate should not change much, if any, because there have been no structural changes in the economy or industry to support it.

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[40] Dr. Aswath Damodaran, Professor of Finance of the New York University Stern School of Business, advocates using a multi-stage methodology if the constant-growth rate is expected to be 1-2% different than the earlier stage growth rates. Aswath Damodaran, *Investment Valuation: Tools and techniques for determining the value of any asset*, University Edition, John Wiley & Sons, Inc., 1996, p. 193.

A multi-stage DCF may use either two or more growth stages, depending on the situation being modeled. In any case, the last stage must use a sustainable rate as it is considered to last into perpetuity. In fact, in Staff's experience, most DCF analyses do not assume a growth rate much higher than the expected rate of inflation, currently 2.0% to 2.5%. The ability of a multi-stage DCF analysis to reliably estimate the cost of common equity is primarily driven by the analyst using a reasonable growth rate for the final stage because this rate is assumed to last into perpetuity. Where three stages are used, the second stage is generally a transitional phase between the high growth first stage and the constant growth final stage.[41]

In the present case, Staff used a three-stage DCF approach, the stages being years 1-5, years 6-10, and years 11 to infinity.[42] For stage one, Staff gave full weight to the analysts' five-year EPS growth estimates. Staff adopts these EPS estimates for the first stage of its model, because Staff understands that these projections are designed to represent expectations over this same 5-year period. For stage two, Staff linearly reduced the growth rate from the stage one level to the constant-growth third stage level, in which Staff assumed a perpetual growth rate range of 3.00% to 4.00%; mid-point 3.50% (*see* Schedules 13-1 through 13-3). Based on this set of assumptions, Staff's estimated the cost of equity for the three proxy groups as follows: 6.90% to 7.70% for the broad proxy group; 6.95% to 7.75% for the pure-play proxy group; and 6.90% to 7.70% for the 2014 refined proxy group.

ii. Stage one

The first stage of a multi-stage DCF is usually quite specific due to the ability to forecast cash flows in the near-term with more accuracy. In fact, it is often the case that the first stage of a multi-stage DCF will be based on discrete cash flows projected on an annual basis for the next several years. However, in the context of discounting expected future DPS, it is often the case that a compound growth rate is applied to the current DPS to estimate the expected DPS over the next several years. Although it is rare for a company to tie its targeted DPS growth rate directly to a 5-year EPS projected compound growth rate, because equity analysts' 5-year EPS forecasts are widely available and may provide some insight on expected DPS, Staff decided to use these growth rates for the first 5-years of its multi-stage DCF. However, Staff emphasizes that it has **never** seen an investment analysis of a utility company that used 5-year EPS forecasts for

[41] 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. 71-72.
[42] In practice, Staff extended the third stage only to year 200.

purposes of estimating the growth in DPS in a single-stage, constant-growth DCF or for the final stage in a multi-stage DCF. Considering the fact that the very equity analysts that provide 5-year EPS compound growth rates do not use them as a proxy for expected long-term DPS growth in their own analyses should be proof in and of itself that stock prices do not reflect this assumption. Consequently, Staff limited its use of these growth rates to the first five years of its analysis, the very period these growth rates are intended to cover.

iii. Stage two

Stage two, i.e. the transition stage, is simply a gradual movement from above normal growth to more normal/sustainable growth for the final stage. Although stage two can also consist of forecasted discrete cash flows, because it is a transitional period, it is logical to linearly reduce the high growth first-stage growth over a specific period in order to gradually reduce the growth rate to the expected sustainable growth rate. Staff chose to do this over a 5-year period, which is fairly conventional in multi-stage DCF analysis.

iv. Stage three

Stage three is the final/constant-growth stage. In fact, the final stage can be reduced to the single-stage, constant-growth form of the DCF. Although this is the "generic" stage, it is extremely important to select a reasonable growth rate for this stage to arrive at a reliable cost of equity estimate.

Cost of equity estimates using multi-stage DCF methodologies are **extremely sensitive** to the assumed perpetual growth rate. Staff performed an extensive amount of research on the actual realized growth rates of electric utilities over a 30-year period to estimate a 3.00% to 4.00% growth rate as a reasonable proxy for perpetual growth for the electric utility industry.

The Financial Analysis Unit has access to Value Line data on *Central* region electric utility companies dating back to 1968.[43] Staff believes it is important to analyze electric utility industry financial data to at least the early 1970s since this was approximately the beginning of the last large construction cycle for the electric utility industry.[44] Because 1968 is consistent

[43] Value Line has consistently published information the electric utility industry based on three regions: East, West and Central. The Central Region electric utility industry data is published in Edition 5 of The Value Line Investment Survey data. Staff maintained consistent and comprehensive files for the Central Region for reports published back to 1985, which provides electric utility per share data dating back to 1968.

[44] Daniel Ford, Gregg Orrill, Theodore W. Brooks, Ross A. Fowler, M. Beth Straka and Noah Howser, "Utilities Capital Management," July 16, 2009, Barclays Capital, p. 13.

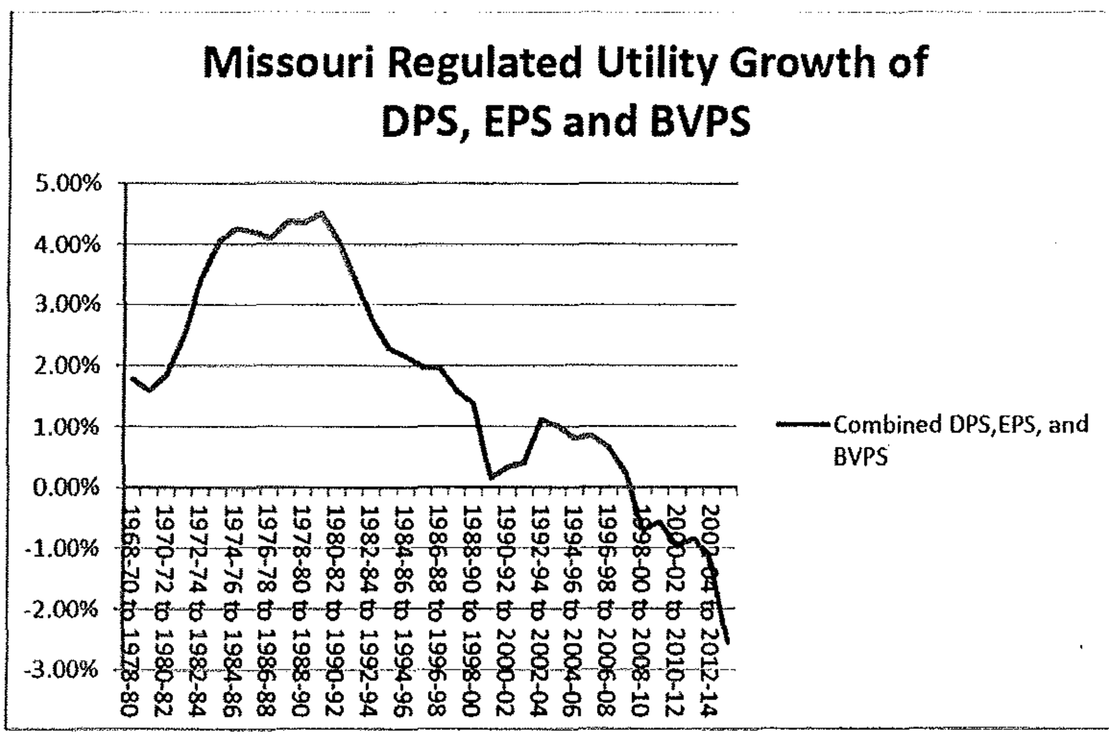
with the starting point of the last construction cycle, Staff decided to capture data starting in that year. Ideally, Staff would have analyzed data through the beginning of the current construction cycle, which started approximately during the middle of the past decade, but because many electric utility companies diversified into non-regulated merchant and trading operations towards the end of the 1990s and there was much consolidation during this same period, this noise causes any study relying on this more recent data to be less reliable in evaluating *regulated* electric utility growth rates. It appears that much of the disruption in the electric industry occurred subsequent to the Enron, Inc., bankruptcy in December 2001. Considering that much of this disruption was caused by deregulation, Staff does not consider the information during this period to be informative for understanding investors' growth expectations for regulated electric utility operations.

Staff did not apply rigid selection criteria for purposes of selecting central region electric utility companies contained in Edition 5 of the Value Line Investment Survey. However, Staff did eliminate companies that generally did not have at least 70% of revenues from electric utility operations in the late 1990s. Staff also eliminated companies that appeared to be impacted significantly by events related to the restructuring of the electric utility markets in the mid to late 1990s. Staff also eliminated companies that had data comparability problems due to major mergers, acquisitions and/or restructurings. Staff only included companies in which comparable data was available for each year of the period 1968 through 1999. The companies Staff selected are shown in Schedules 13-1 through 13-4.

Staff's analysis of these electric utility companies' data over the last electric utility construction cycle indicates that average long-term growth slowly increased through the late 1980s and early 1990s and declined for the rest of the 1990s. The growth rates are based on Staff's calculation of a simple average of all of the companies' growth rates over this period. Because a simple average gives each company equal weight, Staff believes this approach is appropriate because it does not introduce size bias. As can be seen in the attached Schedules, the rolling average 10-year compound EPS growth rate for this period was 3.62%; the rolling 10-year compound DPS growth rate was 3.99%; the rolling 10-year compound BVPS growth rate was 3.18%; and the overall average for DPS, EPS and BVPS was 3.59%.

However, it is important to understand that these growth rates were achieved during a much more robust economic environment than the U.S. is expected to achieve in the foreseeable future. Also, considering that some rate of return witnesses' DCF analyses assume utilities can grow at the same rate as GDP in perpetuity, it is interesting to note that the average growth rate for these electric utilities was less than 50% of GDP growth over the same period.

Although Staff relied on the aforementioned proxy group for purposes of estimating a going forward sustainable industry growth rate, another relevant proxy group to evaluate growth trends for electric utility companies is the growth of the utility companies that actually have a large amount of their electric utility operations in Missouri. In addition to evaluating the growth of Missouri electric utility companies for the period 1968-1999, Staff also evaluated the growth of Missouri electric utility companies through 2015. As can be seen in the chart below, if the growth rates of the Missouri utilities are evaluated for the period after the 20th century, it is quite apparent that including this period would reduce the actual realized growth rate:



The average 10-year compound growth rates in DPS, EPS and BVPS for the period 1968 through 2015 were 1.50%, 1.30% and 2.30%, respectively, with an overall average growth rate of 1.70%. The average 10-year compound growth rates in DPS, EPS and BVPS for the period 1968 through 1999 were 3.59%, 3.00% and 2.57%, respectively, with an overall average growth rate of 3.05%. Consequently, including more recent financial data in evaluating the growth rate trends of Missouri's electric utilities actually supports the use of a lower perpetual growth rate than most

ROR witnesses assume for a constant/perpetual growth rate. The above graph certainly would cause a rational investor to be skeptical of anyone that suggests their investment would consistently grow at a rate of 5% for any period of time, let alone in perpetuity.

Of Missouri's utilities, The Empire District Electric Company's business operations have been the most consistent in being limited to regulated utility operations through the period analyzed. Although Great Plains Energy has owned some non-regulated operations during the period Staff analyzed (e.g., Strategic Energy), these operations did not disrupt the financial performance of the Company to a great extent, even though they did increase Great Plains Energy's risk profile. However, Ameren Missouri has incurred significant financial problems due to its ownership of merchant generation operations in Illinois. This exposure caused Ameren Missouri to incur significant losses in recent years, which would skew any financial growth rates that include this information. Although Empire and Great Plains Energy did not incur financial difficulties due to non-regulated operations, both companies did reduce their dividends in recent years. Because of these issues that occurred around or after the recession and financial crisis in 2008 and 2009, Staff also determined the average growth of Missouri's utilities through 2007. The average 10-year compound growth rates in DPS, EPS and BVPS for the period 1968 through 2007 were 2.85%, 2.03% and 2.27%, respectively, with an overall average growth rate of 2.39%.

Obviously, the actual experienced growth rates of Missouri's electric utilities support the reasonable, if not lofty, perpetual growth rates Staff chose to use for its perpetual growth rate analysis. The actual realized growth rates of Missouri's utilities support a perpetual growth rate range of 2% to 3% rather than the 3% to 4% Staff decided to use. Although these growth rates are generally characterized as "low" when discussed in the utility ratemaking arena, these growth rates are more typical of those that are used by investors when determining a reasonable price to pay for a utility stock.[45] Additionally, considering that the dividend yield from utility stocks has historically produced 2/3 of the total return on utility stocks,[46] and the fact that dividend yields for electric utilities are currently approximately 3.3% to 3.4%, a 1.65% capital appreciation rate in utility stocks is about what investors would expect going forward. This translates into an

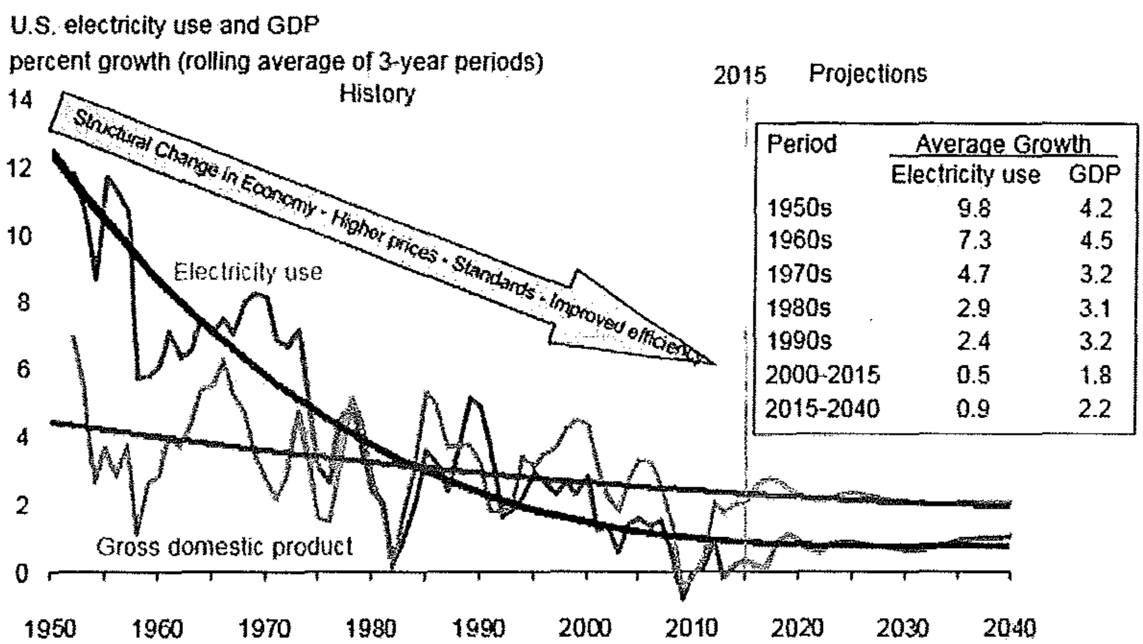
[45] Staff has analyzed many utility stock research reports over the last several years and has consistently observed much lower perpetual growth rates than those typically assumed in models for estimating the cost of equity for utility ratemaking.

[46] Hugh Wynne, Francois D. Broquin, Saurabh Singh, "U.S. Utilities: Our Dividend Growth Model Identifies Utilities Poised to Pay More," May 20, 2011, Bernstein Research.

approximate expected return of approximately 5% for utility stocks, which is quite logical and rational in the current low-yield environment.

v. Constraints on Long-term Growth Rates used in Stage Three

In order to evaluate the credibility of an estimated perpetual growth rate for the electric utility industry, it is important to be aware of the changing fundamentals that have occurred and continue to occur within the electric utility industry due to changes in demand for electricity. In the past, growth in electric utility earnings and dividends was primarily driven by the increase in demand for electricity and the growth of customers using electricity. However, this dynamic has changed and the demand for electricity is no longer a primary growth driver for electric utilities. The decline in electricity demand growth is illustrated in the graph below:[47]



Source: EIA, Annual Energy Outlook 2016

The fact that the growth in electricity demand has been in a steady state of decline seems to explain the steady decline in electric utilities' financial performance over the period Staff analyzed in its previous discussion in this testimony. To the extent that potential financial growth for electric utilities is now limited to the ability to make additional investments and pass the cost of these investments (which includes the allowed ROR) on to a near-constant customer base, any growth higher than needed capital investment to replace existing infrastructure would

[47] Energy Information Administration's *2016 Annual Energy Outlook.*

seem to be highly speculative and not sustainable. However, Staff notes that much of the rate base growth for electric utilities in recent years has been due to electric utilities making investments in order to comply with various environmental standards, such as the Mercury Air Toxic Standards ("MATS"), renewable portfolio standards, energy efficiency investments and other policy driven type of investments such as smart meters and grid modernizations. Also, to the extent that the economy is growing at a very slow rate and certain energy efficiency advancements do result in lower growth in electricity use, it is hard to understand how much growth electric utility companies can achieve. Morgan Stanley recently indicated that it was contemplating electricity demand declines of 0.3% annually for the next decade.[48]

vi. Preference for GDP Growth

Although Staff is confident that investors do not expect that utilities' per share growth rates can grow at the same rate of nominal GDP in the long-run, Staff recognizes that even customer ROR witnesses have been willing to accept this assumption for purposes of estimating the cost of equity. Consequently, Staff will provide a cost of equity indication using this simplified approach.

Projected GDP growth is available from a variety of sources, such as the Congressional Budget Office ("CBO"), the Federal Reserve, the EIA, and Blue Chip Economic Forecasts. Staff will use the CBO, EIA, The Survey of Professional Forecasters published by the Philadelphia Federal Reserve, The Federal Open Market Committee ("FOMC"), and The Livingston Survey for purposes of long-term projected GDP growth. The CBO projects an annual compound growth rate in nominal GDP of approximately 4.1% through 2026.[49] EIA's reference case projects an annual compound growth rate in nominal GDP of approximately 4.35% for the period 2014 through 2040,[50] The Survey of Professional Forecasters projects a 10-year annual compound growth rate in real GDP of 2.28%;[51] The Livingston Survey for June 2016 projects an average annual compound growth rate in real GDP of 2.20% over the next ten years;[52] and the FOMC projects a central tendency long-term real GDP growth of only 1.8% to 2.0%.[53] In each

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[48] Dan Testa, "Utility CapEx to peak in 2016, but can it continue?," June 24, 2016, SNL Marketweek.
[49] https://www.cbo.gov/about/products/budget_economic_data#4.
[50] https://www.eia.gov/forecasts/aeo/data/browser/#/?id=18-AEO2016&cases=ref2016~ref_no_cpp&sourcekey=0.
[51] https://www.philadelphiafed.org/research-and-data/real-time-center/survey-of-professional-forecasters/2016/survq116.
[52] https://www.philadelphiafed.org/research-and-data/real-time-center/livingston-survey.
[53] https://www.federalreserve.gov/monetarypolicy/files/fomcprojtabl20160615.pdf.

case in which the sources do not project a nominal GDP growth rate, Staff recommends adding a GDP price deflator of 2.0%, which is the CBO's approximate prediction of long-term inflation and also the inflation rate which is targeted by the Federal Reserve. Based on these projections, the long-term nominal GDP growth rate is expected to be approximately in the range of 3.84% to 4.35%. These projected long-term growth rates in U.S. GDP are consistent with the current low interest rate environment, which implies a low growth, low rate of return environment. Considering that the mid-point of the range of projected long-term GDP growth rates is approximately 30 basis points lower than the 4.4% projected GDP growth rates at the time Staff prepared its testimony in the 2014 rate cases, it is logical that Staff's use of the same perpetual growth rates that it used in 2014 causes Staff to underestimate the decline in the cost of equity since 2014.

Regardless, Staff will hold the GDP growth rate it used in 2014 constant in order to show the impact of the increase in utility valuation levels on implied cost of equity estimates. Using a 4.4% GDP growth rate in Staff's multi-stage DCF results in a COE estimate of approximately 8.04% for the 2014 refined proxy group, which is approximately 60 basis points lower than Staff's results in 2014. If Staff had used a 4.1% GDP growth rate, the multi-stage DCF analysis would imply a COE estimate of 7.80%, which implies that the cost of equity has declined by up to 90 basis points.

d. Relative Changes to Multi-Stage DCF Cost of Equity Estimates

Perhaps the most useful analysis to assist the Commission with determining a fair and reasonable allowed ROE in this case is to evaluate the implied cost of equity changes since the Commission last allowed ROEs of approximately 9.5% for KCPL and Ameren Missouri in 2015 for their 2014 rate cases. Although Staff's analysis in the recent Missouri-American and Empire rate cases did not show clear and convincing evidence that the cost of equity had changed significantly since the Commission last made allowed ROE determinations, utility stocks have rallied significantly since this time, causing much lower implied cost of equity estimates from Staff's multi-stage DCF analyses. As Staff explained earlier in this section of the report, Staff relied on capital market data through the fall of 2014 to estimate a 25 to 75 basis point reduction to the electric utility industry's cost of equity from 2012 to 2014. As Staff continued to update its cost of equity analysis through the Empire and KCPL rate cases, Staff's estimated decline in the electric utility industry's cost of equity had increased to approximately 100 basis points by early 2015. This justified consideration of lowering the allowed ROEs to around 9%, but Staff chose to use the same quantification for all the rate cases.

It is important for the Commission to understand that the current electric utility equity markets are more similar to the environment that occurred when Staff was performing its analysis for the KCPL rate case rather than when it was performing its analysis in the Ameren Missouri rate case in the fall of 2014. In fact, the p/e ratios are higher than they were in early 2015 even though utility bond yields have not dropped to as low as they were in early 2015. The primary driver for the higher utility equity prices is the continued decline the long-term Treasury bond yields with the 10-year Treasury trading at a yield of approximately 1.4% recently. In early 2015, the 10-year Treasury didn't drop to below 1.7%.

Consequently, when Staff compared the multi-stage DCF analyses in this case to those done in the 2014 rate cases and the recent Empire rate case (*see* Schedule 14), Staff gave more consideration to the implied change in the cost of equity between the Ameren Missouri rate case and this case because the data from the Ameren Missouri rate case formed the basis for Staff's 25 to 75 basis point estimated declined in the cost of equity. As can be seen in this schedule, the implied cost of equity decline is approximately 70 basis points as compared to Staff's analysis in the Ameren Missouri rate case, while it is only 15 basis points as compared to the KCPL rate case. This schedule also shows that the implied cost of equity has declined by 40 basis points since Staff performed its analysis in the recent Empire rate case, Case No. ER-2016-0023.

Staff believes the 70 basis point estimate may be slightly underestimated due to the fact that over the last couple of years the projections for long-term economic growth have continued to decline. Most economists have lowered the expected long-term GDP growth estimates to slightly over 4%, when in 2014 there were still projections closer to 4.5%. Undoubtedly this has had an impact on the expected long-term growth for all companies that operate in the United States, including utilities. Consequently, Staff compared its multi-stage DCF analysis using a 4.4% GDP growth rate in 2014 to that of its multi-stage DCF analysis in this case using a 4.1% GDP growth rate. This comparison implies a cost of equity declined of up to 90 basis points for the electric utility industry, which forms the basis for the lower end of Staff's recommended allowed ROE range.

G. Tests of Reasonableness

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

1. <u>The CAPM</u>

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 2015. For the risk-free rate ("Rf"), Staff used the average yield on 30-year U.S. Treasury bonds for the three-month period ending June 30, 2016; that figure was 2.57%. For beta ("β"), Staff relied on estimates directly calculated through an Excel spreadsheet designed specifically to be used with the SNL database of market and financial information. Although Staff is no longer using Value Line's published betas for purposes of its CAPM analysis in its direct testimony, because Value Line is used by many retail investors, Staff still believes Value Line's beta calculation methodology should be considered when performing a CAPM analysis. Because estimating beta is a matter of having access to financial data and performing statistical calculations, unless a financial services provider has a proprietary adjustment they make to their beta calculation, understanding the methodology used by a financial provider allows an analyst to approximately replicate betas of that provider. Fortunately, this is the case for Value Line's beta calculation methodology. Consistent with Value Line's approach to calculating beta, Staff used 5-years of historical weekly returns of the subject company and the New York Stock Exchange ("NYSE") index. The covariance of the weekly returns on the NYSE index and the weekly returns on the subject company is divided by the variance of the weekly returns on the NYSE index to determine raw beta (unadjusted beta). Staff then adjusted the raw beta using the Blume adjustment formula as used by Value Line: Adjusted Beta = (.35 + .67(Unadjusted Beta)) (*see* Schedule 15).

The average betas for the proxy groups were as follows: 0.71 for the broad proxy group, 0.70 for the pure-play proxy group and 0.69 for the 2014 refined proxy group. For the market risk premium (Rm – Rf) estimates, Staff relied on the historical difference between earned returns on stocks and earned returns on bonds.[54] The first risk premium was based on the long-term arithmetic average of historical return differences from 1926-2015 – 6.00%. The second risk premium was based on the long-term geometric average of historical return differences from 1926 to 2015 – 4.40%. The results using the long-term arithmetic average risk premium and the long-term geometric risk premium are 6.85% and 5.71%, respectively for the broad proxy group; 6.75% and 5.64%, respectively for the pure-play proxy group; and 6.72% and 5.61%, respectively for the 2014 refined proxy group.

These cost of common equity results support the reasonableness of Staff's 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 early 1960s) and that the spread between them is presently below their long-term average. It is highly probable that investors are only requiring returns on common equity in the 5 to 6 percent range for utility stocks. In fact, as Staff will explain in its other tests of reasonableness, these cost of equity estimates are consistent with common sense tests and costs of equity used by investors to value utility stocks.

[54] From Duff & Phelps *2016 Valuation Handbook: A Guide to the Cost of Capital.*

2. Other Tests

a. The "Rule of Thumb"

A "rule of thumb" method allows an objective test of individual analysts' cost of equity estimates. Because this method is suggested in a textbook[55] used for the curriculum for Chartered Financial Analyst ("CFA") Program, Staff believes this method is free of any bias from those involved in utility ratemaking. It is also a useful test because it is very straightforward and limits the risk premium to a 100 basis point range. The cost of equity is estimated by simply 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% range. Considering that this is based on general U.S. capital-market experience and that regulated utilities are on the low end of the risk spectrum of the general U.S. market, a risk premium closer to 3% seems logical. This is especially true considering that regulated utility stocks behave like bonds. For the three months ended through June 2016, Moody's "A" rated and "Baa" rated long-term public utility bonds had average yields of 3.90% and 4.61% respectively.[56] Adding a 3% risk premium, the "rule of thumb" indicates a cost of common equity between 6.90% and 7.61%. Adding a 4% risk premium, the "rule of thumb" indicates a cost of common equity between 7.90% and 8.61%.

Of course, these are just generic indices. Because GPE has long-term bonds that are traded over the counter, it is very informative to look to these yields to at least provide some insight as to a specific estimate of GPE's rule of thumb cost of equity. This bond matures in 2041 so it is has a long enough maturity to be considered consistent with the 20 plus years left to maturity of bonds evaluated by Moody's and Value Line. The average yield for this bond was 4.32% for the period April, May and June 2016, which implies a cost of equity of approximately 7.32% to 8.32%.

b. Average Authorized Returns

In the past, the Commission has applied a test of reasonableness using average authorized returns published by Regulatory Research Associates ("RRA") to test the reasonableness of its allowed ROE. According to RRA, the average authorized return on equity

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[55] 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.
[56] June 2016 Mergent Bond Record.

authorized electric utilities was 10.26% in the first quarter of 2016 (based on 8 ROE determinations), compared to a 2015 calendar year average of 9.85% (based on 30 ROE determinations).[57] Excluding the effect of the surcharge/rider generation cases in Virginia, the average allowed electric ROEs were 9.68% for the first quarter of 2016, 9.58% for the 2015 calendar year and 9.76% for the 2014 calendar year.

In order to provide more specific information on the allowed ROE's by type of electric utility operations, Staff determined the allowed ROEs that were given to integrated electric utility companies. Staff excluded allowed ROEs that were determined for dockets not involving a full general rate case (i.e. rider only cases). Staff also continued to exclude the aforementioned Virginia rate cases. The average allowed ROE for integrated electric utilities for the first quarter of 2016 was 9.70%. The average allowed ROE for integrated electric utilities was 9.75% for the 2015 calendar year and 9.94% for the 2014 calendar year.

As a further refinement, Staff also evaluated allowed ROE information for only cases that were fully-litigated as in these cases, one would expect that each issue is determined based on its own merits. Allowed returns determined in context of a settled case are not as reliable because parties make adjustments to other elements of the ratemaking formula in order to arrive at an overall reasonable number. It has been Staff's experience, that some companies do not want a lower ROE published in a settlement because this is a headline number. Consequently, companies may compromise on a more obscure area of the rate case in order to have a higher ROE published in the settlement. The average allowed ROE for fully-litigated cases in the first quarter of 2016 was 9.85% (one decision for a fully litigated integrated electric utility case). Allowed ROEs for fully-litigated cases were 9.74% for the 2015 calendar year, and 10.03% for the 2014 calendar year.

c. Investment Community Requirements and Expectations

In past testimonies, Staff has consistently provided information from the investment community that corroborates Staff's position that allowed ROEs are higher than the cost of equity to utility companies. The cost of equity is the discount rate equity analysts use to determine the present value of expected future cash flows the utility is expected to generate.

[57] RRA, Regulatory Focus – Major rate case decisions (January-March 2016) - April 15, 2016: first quarter 2016 data includes five surcharge/rider generation cases in Virginia that incorporate plant-specific ROE premiums. Virginia statutes authorize the State Corporation Commission to approve ROE premiums of up to 200 basis points for certain generation projects.

Equity analysts may apply this discount rate specifically to expected dividends in a dividend discount model or to free cash flow available to the equity investor in determining the estimated value of equity. In either case, the equity analyst is advising investors as to what they believe the stock may be worth based on economic, industry and company-specific expectations. Equity analysts have come to expect commissions to allow ROEs higher than the cost of equity. In fact, if the allowed ROE to cost of equity spread becomes too wide, they believe commissions will eventually lower allowed ROEs to narrow this spread. Staff has discovered specific evidence that some equity analysts believe that the current "lower for longer" interest rate environment will eventually cause downward pressure on allowed ROEs.

In a presentation made at the recent Society of Utility Regulatory and Financial Analysts' (SURFA) Forum on April 28 and April 29, 2016, Greg Gordon, CFA, Senior Managing Director, Evercore ISI, provided three potential investment scenarios: (1) ROEs Fade and Rates Rise, (2) Rates Low for Long Time and (3) ROEs Flat and Rates Rise. Regardless of the scenario, Mr. Gordon's assumed cost of equity to allowed ROE spread in the terminal year was 2.25%. Consequently, in order for scenario (1) to result in an allowed ROE to cost of equity spread of 2.25%, the allowed ROE would fall to 9.5% in the final year, but the cost of equity would increase to 7.25% based on annual cost of equity increase of 0.38% each year over the next four years. This means that at least as of April 25, 2016, Evercore ISI estimated the cost of equity to be approximately 5.75% for the electric utility industry, which means that investment analysts view an allowed ROE of 9.5% as a 3.75% margin over the cost of equity, which is far higher than their expectations. However, investors don't expect commissions to reduce ROEs to a 225 basis point spread all at once. In fact, in two of the scenarios, the 225 basis point spread would only be achieved if interest rates rise, causing the cost of equity to rise rather than allowed ROEs falling to cause the usual 225 basis point spread. In the scenario that seems to be gaining traction in the current capital and economic environment, the cost of equity is expected to gradually fall at 5 basis point increments over the next ten years to a level of 5.25%. However, in order for the expected 225 basis point spread between the cost of equity and the allowed ROE to occur, this scenario assumes that commissions will lower allowed ROEs by 25 basis points every year for the next 10 years so that allowed ROEs will gradually fall to 7.5%.

Although Staff recognizes that most parties, including itself, have argued that the allowed ROE should be premised on the cost of equity, the investment community recognizes and actually expects a margin of allowed ROEs over the cost of equity. While the proper spread over the cost of equity, if any, for an allowed ROE would result in as much debate as what the true cost of equity is, this is beyond the scope of Staff's testimony in this case. Staff's intention is to communicate to the Commission that the current spread of allowed ROEs to the cost of equity is higher than investors are accustomed to and in fact, they expect it to compress either by allowed ROEs falling, the cost of equity increasing or both.

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 GMO's prudent cost of service, which includes an allowed ROR. Using widely-accepted methods of financial analysis, Staff believes the cost of common equity has is approximately 50 basis points lower as compared to 2014, with a range of 15 to 85 basis points.

Consequently, Staff recommends the Commission reduce its authorized ROE for GMO to a range anywhere between 8.65% to 9.35% to at least partially share the reduced cost of equity with ratepayers. Given that the cost of capital is as real a cost as any other cost of service, reducing this cost in the ratemaking formula is consistent with the principles of cost of service ratemaking. Using this recommended allowed ROE results an allowed ROR for GMO in the range of 6.99% to 7.34% (*see* Schedule 16). This rate was calculated by applying an embedded cost of long-term debt of 5.41%, embedded cost of preferred stock return of 4.29% and an allowed return on common equity range of 8.65% to 9.35% to a capital structure consisting of 49.01% common equity, 0.52% preferred equity and 50.46% long-term debt. If the Commission lowers the allowed ROE to 9%, this will allow a reasonable compression in the spread between the allowed ROE and the cost of common equity. This allowed ROE would balance the concern about the impact of a lower allowed ROE on investors' view of Missouri's regulatory environment, while still passing along the benefit of lower capital costs to ratepayers.

Staff Expert/Witness: David Murray

VI. Rate Base

A. Plant-in-Service and Accumulated Depreciation Reserve

Staff included the plant-in-service ("plant") and the accumulated depreciation reserve ("reserve") balances as of the update period, December 31, 2015, based on actual booked amounts (Data Request No. 0027) for total GMO consolidation, and separately for GMO's MPS and L&P rate districts. Total GMO consolidation is the combination of MPS and L&P rate districts. Since historically, the MPS and L&P rate districts have been accounted for separately, it was necessary to combine the plant balances of the two separate districts in order to develop a level of plant balances for total GMO combined. These balances include plant additions and retirements that have occurred since the end of the test year (the twelve months ending June 30, 2015) and the related depreciation reserve balances. At the time of the true-up, adjustments to the plant balances Staff used for its direct filing will be updated to include amounts for plant additions that have become fully operational and used for service and retirements that have occurred as of July 31, 2016, the true-up cut-off date. Staff will also make a true-up adjustment to update for depreciation reserve balances related to those additions and retirements. Plant must be "fully operational and used for service" before it is appropriate to reflect that plant and its associated reserve in rates.

The plant balance for GMO for the period ending December 31, 2015, is identified on the Plant Accounting, Schedule 3, and the accumulated depreciation reserve as of that date is identified in the Depreciation Reserve, Accounting Schedule 6. The information in Accounting Schedules 3 and 6 for plant and reserve, respectively, are shown by Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA") for each plant category, broken out for production, transmission, distribution and general facilities.

During the review of GMO's plant reserve balances, Staff found GMO had made adjustments to the reserve account balances for retirement work in progress ("RWIP").[58] GMO removed the retired plant and related depreciation reserve from its plant and reserve account balances as of the retirement dates. However, as of December 31, 2015, GMO had not removed the related reserve for cost of removal and salvage for the retired plant. As a result, GMO's books overstate the reserve for this retired plant; therefore, Staff reflected the RWIP in the

[58] "RWIP" is retired plant that has not yet been classified for certain components of depreciation, namely cost of removal and salvage.

reserve to remove the plant that was no longer being used for service from the reserve balances. Staff included a line item in the accumulated depreciation schedule, identifying the RWIP associated with production, transmission, distribution, and general plant.

Depreciation expense is based on Staff witness Derick Miles' recommended depreciation rates that were applied to the adjusted Missouri jurisdictional plant balances as of December 31, 2015. This will be further discussed in the Income Statement section of Staff's Cost of Service Report in the Depreciation Expense section.

Other plant and reserve adjustments were necessary based on prior stipulation and agreements and on past orders of the Commission. The plant adjustments will be discussed below in the section relating to the Crossroads Energy Center and the reserve adjustments will be discussed in the section relating to the stipulation and agreement adjustments agreed to by GMO and Staff in Case No. ER-2012-0175. Plant, reserve and depreciation expense will be included in the true-up in this case through the period ending July 31, 2016.

The following table identifies KCPL and GMO electric utility generation resources for 2016, as stated in Great Plains Energy's SEC 10-K. filing:

	Unit	**Location**	**Year Completed**	**Estimated 2016 MW Capacity**	**Primary Fuel**
Base Load	Iatan No. 2	Missouri	2010	482(a)	Coal
	Wolf Creek	Kansas	1985	549(a)	Nuclear
	Iatan No. 1	Missouri	1980	499(a)	Coal
	LaCygne No. 2 343 MW (a) in 2013	Kansas	1977	699 combined	Coal
	LaCygne No. 1—368 MW (a) in 2013	Kansas	1973	See above	Coal
	Hawthorn No. 5(b)	Missouri	1969	564	Coal
	Montrose No. 3	Missouri	1964	176	Coal
	Montrose No. 2	Missouri	1960	164	Coal
	Montrose No. 1 [Retire in 2017]	Missouri	1958	0	Coal
Peak Load	West Gardner Nos. 1-4	Kansas	2003	310	Natural Gas
	Osawatomie	Kansas	2003	75	Natural Gas
	Hawthorn No. 9	Missouri	2000	130	Natural Gas
	Hawthorn No. 8	Missouri	2000	77	Natural Gas
	Hawthorn No. 7	Missouri	2000	77	Natural Gas
	Hawthorn No. 6	Missouri	1997	136	Natural Gas
	Northeast Black Start Unit	Missouri	1985	2	Oil
	Northeast Nos. 17-18	Missouri	1977	110	Oil

	Unit	Location	Year Completed	Estimated 2016 MW Capacity	Primary Fuel
	Northeast Nos. 13-14	Missouri	1976	95	Oil
	Northeast Nos. 15-16	Missouri	1975	106	Oil
	Northeast Nos. 11-12	Missouri	1972	93	Oil
Wind	Spearville 2 Wind Energy Facility (c)	Kansas	2010	15	Wind
	Spearville Wind Energy Facility (d)	Kansas	2006	31	Wind
Total KCP&L				**4,360**	
	Unit		**Year Completed**	**Estimated 2016 MW Capacity**	**Primary Fuel**
Base Load	Iatan No. 2	Missouri	2010	159(a)	Coal
	Iatan No. 1	Missouri	1980	128(a)	Coal
	Jeffrey Energy Center Nos. 1, 2 and 3	Kansas	1978, 1980, 1983	172(a)	Coal
	Sibley Nos. 1, 2 and 3	Missouri	1960, 1962, 1969	461	Coal
	Lake Road Nos. 2 and 4	Missouri	1957, 1967	115	Coal and Natural Gas
Peak Load	South Harper Nos. 1, 2 and 3	Missouri	2005	303	Natural Gas
	Crossroads Energy Center	Mississippi	2002	292	Natural Gas
	Ralph Green No. 3	Missouri	1981	71	Natural Gas
	Greenwood Nos. 1, 2, 3 and 4	Missouri	1975-1979	247	Natural Gas/Oil
	Lake Road No. 5	Missouri	1974	62	Natural Gas/Oil
	Lake Road Nos. 1 and 3	Missouri	1951, 1962	16	Natural Gas/Oil
	Lake Road Nos. 6 and 7	Missouri	1989, 1990	42	Oil
	Nevada	Missouri	1974	18	Oil
Total GMO				**2,086**	
Total Great Plains Energy				**6,446**	

a. Share of a jointly-owned unit.

b. In 2001, a new boiler, air quality control equipment and an uprated turbine was placed in service at the Hawthorn Generating Station.

c. The 48 MW Spearville 2 Wind Energy Facility's accredited capacity is 15 MW pursuant to SPP reliability standards.

d. The 100.5 MW Spearville 1 Wind Energy Facility's accredited capacity is 31 MW pursuant to SPP reliability standards.

Source: GREAT PLAINS ENERGY INC. 10-K. as of December 31, 2015—page 22.

Staff Expert/Witness: Cary G. Featherstone

B. Crossroad Energy Center Valuation

Staff continues to recommend that the Commission include the Crossroads Energy Center ("Crossroads") in total GMO combined rate base for MPS in this proceeding consistent with the Commission's decision in GMO's 2010 rate case, Case No. ER-2010-0356. The Commission re-affirmed its 2010 rate case decision in GMO's 2012 rate case, Case No. ER-2012-0175. Since GMO's 2009 rate case (Case No. ER-2009-0090), the Commission has consistently adopted a valuation and a level of supporting operating costs for Crossroads consistent with the costs Great Plains would have paid to acquire Crossroads as part of its July 14, 2008, acquisition of Aquila. The Commission determined the appropriate July 14, 2008, value of Crossroads to be $61.8 million. An offset for accumulated depreciation reserve also had to be included in GMO's rate base to reflect depreciation for Crossroads accumulated since the acquisition. As of December 31, 2015, that accumulated depreciation is $15.7 million. The plant-in-service value of Crossroads as of December 31, 2015, consistent with the Commission's decisions in the 2010 and 2012 GMO rate cases, is $63.9 million. GMO calculated the rate base value for Crossroads at the December 31, 2015, end of update period, as follows:

December 31, 2015	
Plant in Service	**$63,862,792**
Accumulated Depreciation	**15,721,894**
Net Crossroads Plant After Adjustments	**$ 48,140,898**

In this case, Staff has had to make a series of adjustments to both plant and reserve in the generation and transmission plant accounts to properly reflect the valuation the Commission determined in GMO's 2010 rate case and reaffirmed in the 2012 rate case. These plant and reserve adjustments to generation and transmission accounts were necessary because GMO has not written down the plant and reserve values to the Commission determined levels. Staff made the following adjustments to reflect the previous Commission decisions:

continued on next page

FERC Plant Account Number	Plant Account Description	GMO Combined Plant Adjustment	GMO Combined Reserve Adjustment
303.01	Miscellaneous Intangible-Substation	P-181	R-181
340	Land	P-182	N/A
341	Structures	P-183	R-183
342	Fuel Holders	P-184	R-184
343	Prime Movers	P-185	R-185
344	Generators	P-186	R-186
345	Accessory	P-187	R-187
346	Miscellaneous Power Plant Equipment	P-188	R-188

Source: Accounting Schedules for GMO Combined and MPS Schedules 4 and 7

Consistent with the Commission decision in GMO's 2010 rate case regarding Crossroads, Staff has included the appropriate level of deferred income taxes as an offset (reduction) to rate base consisted with the value at December 31, 2015.

Also, consistent with the Commission's decision in the last two rate cases (Case Nos. ER-2010-0356 and ER-2012-0175), Staff has excluded GMO's transmission costs associated with Crossroads. Staff made an adjustment to remove the entire amount of test year level of Crossroads transmission expenses.

Background

GMO owns four natural gas-fired combustion turbines at its Crossroads generating station located in Clarksdale, Mississippi, that have a combined capacity of 292 megawatts, according to the Great Plains 2015 Annual Report (page 22, 2015). Aquila Merchant Services, a wholly-owned non-regulated affiliate of Aquila, constructed Crossroads in 2002, with the intent of selling the electricity generated into the non-regulated energy power market. Aquila Merchant made a decision to construct Crossroads in that area of the country to take advantage of transmission constraints. In Staff's view, since this generating facility was built as a merchant plant, Aquila never intended Crossroads to be part of its regulated operations to serve customers' electricity requirements in western Missouri. When the merchant power market collapsed in 2002 after the Enron bankruptcy, Aquila and its affiliates decided to exit the non-regulated energy market and concentrate on traditional regulated operations, primarily the generation, transmission and distribution of electricity in Missouri. At that time, Aquila Merchant began attempting to sell Crossroads and other non-regulated assets because they were not considered necessary to Aquila's regulated operations. While Aquila Merchant sold other non-regulated assets, it found no one interested in Crossroads even when Aquila offered Crossroads at distressed plant discounted values. Because of the 2002 decision to exit the non-regulated energy markets, Aquila never operated Crossroads to sell electricity into the non-regulated energy power markets and Crossroads did not generate any power in 2003, 2004 or 2006.

Great Plains acquired Aquila and its affiliates in July 2008. When it acquired Aquila, it also acquired Crossroads, because, prior to the acquisition, Crossroads had been transferred from Aquila Merchant to a non-regulated subsidiary of Aquila. After Great Plains acquired Aquila, it transferred Crossroads to its plant records for MPS in August 2008. In later rate proceedings, the Commission determined the rate base value of Crossroads to be $61.8 million, which is the average of the per kilowatt values of two combustion turbine facilities Aquila Merchant sold to Ameren Missouri in 2006 that Staff introduced into evidence in that case. In the 2010 rate case and again in the 2012 rate case, the Commission relied on two of those sales transactions—one for the sale of the Raccoon Creek Energy Center and the other for the sale of the Goose Creek Energy Center–to determine the appropriate rate base valuation for Crossroads.

The following appears at page 100 of the Commission's May 4, 2011, Order in Case No. ER-2010-0356:

> The Commission also rejects GMO's inclusion of Crossroads in rate base at its net book value. The Commission determines that given Great Plains' statements to the Securities Exchange Commission shortly before the transfer of the Crossroads unit to the Missouri regulated operations, as well as the arm-length sale of other General Electric combustion turbines by Aquila, that the fair market value of Crossroads at the time of transfer (August 2008) was $61.8 million.

The Commission also stated at page 94 of its May 4, 2011, Order:

> When conducting its due diligence review of Aquila's assets for determining its offer price for Aquila, **GPE would have considered the transmission constraints and other problems associated with Crossroads. It is incomprehensible that GPE would pay book value for generating facilities in Mississippi to serve retail customers in and about Kansas City, Missouri. And, it is a virtual certainly that GPE management was able to negotiate a price for Aquila that considered the distressed nature of Crossroads as a merchant plant** which Aquila Merchant was unable to sell despite trying for several years. Further, it is equally likely that GPE was in as good a position to negotiate a price for Crossroads as AmerenUE was when it negotiated the purchases of Raccoon Creek and Goose Creek, both located in Illinois, from Aquila Merchant in 2006.
> [footnotes omitted; emphasis added]

Consistent with its decision in GMO's 2010 rate case, the Commission reached the same conclusion about Crossroads in GMO's 2012 rate case. In the Commission's January 9, 2013, decision in Case No. ER-2012-0175, it stated at page 57 of its Order under the Discussion, Conclusions of Law and Ruling section the following regarding Crossroads:

> Therefore, the Commission will order that the value of Crossroads for GMO's MPS rate base shall be $62,609,430 without transmission cost. At that value, GMO and Staff agree, the accumulated depreciation is $10,033,437 and the accumulated deferred taxes are $4,333,301. Those values best support safe and adequate service at just and reasonable rates for MPS, so the Commission will order those amounts to be included in GMO's MPS rate base.

GMO obtained court review of the Commission's disallowance of its cost to transmit electricity from Crossroads. Both the Cole County Circuit Court (Case No. 11AC-CC00415) and the Missouri Court of Appeals (Case No. WD75038, *State ex rel. KCP&L Greater Missouri Operations Company v. Missouri Public Service Commission*, 408 SW3d 153 (Mo. App. 2013)) upheld the Commission, and when GMO sought U.S. Supreme Court relief, it declined to review the Commission's decision (Case No. 13-787).

Immediately following the Commission's *Report and Order* in Case No. ER-2010-0356, GMO filed Case No. ER-20120-175, where it again sought net book value and transmission costs for Crossroads. While Case No. ER-2010-0356 was still before the courts, the Commission decided Case No. ER-2012-0175, again relying on comparable sales to value Crossroads and again disallowing transmission costs.

Both because Staff believes the Commission considers its prior determinations of the rate base value of Crossroads as of July 14, 2008, and to disallow the costs to transmit electricity from Crossroads to GMO's retail customers in Missouri to be final, and because Staff believes those Commission determinations to be appropriate because the value of Crossroads is inextricably intertwined with the cost of transmitting electricity from Crossroads, in this case Staff again used the Commission-determined plant value of Crossroads of $61.8 million as of July 14, 2008, the date Great Plains acquired Aquila, as its starting point. Based on this initial $61.8 million plant value, from July 14, 2008, to December 31, 2015, $15.7 million of depreciation has accumulated for Crossroads. However, due to capital additions, the plant-in-service ("plant") value of Crossroads as of December 31, 2015, consistent with the Commission's decisions in Case Nos. ER-2010-0356 and ER-2012-0175, is now $63.9 million.

CROSSROADS DEFERRED INCOME TAXES

Staff has included a level of deferred income taxes ("deferred taxes") relating to Crossroads consistent with the Commission's decision in GMO's 2010 rate case regarding the plant values for that unit. The Commission stated at page 55 of its Order in Case No. ER-2012-0175 that the appropriate value of Crossroads deferred taxes is $4,333,401 as of August 31, 2012, the true-up date in that case. Deferred taxes are now valued as $4,930,053 at December 31, 2015. Staff has included deferred taxes consistent with the approach taken in the 2012 rate cases.

CROSSROADS TRANSMISSION COSTS

Because Crossroads is located in Mississippi, GMO has had to make firm transmission commitments to transport electricity from it to GMO's load center in western Missouri. The Commission noted the costs to do so are significant. On page 86 of its Order in GMO's 2010 rate case, the Commission disallowed transmission costs relating to Crossroads, recognizing they were ongoing and indicating that it would not allow them in future rate cases, as follows:

> Staff argues that the cost of transmission to move energy from Crossroads in Mississippi to GMO's service territory justifies, in part, removing Crossroads from GMO's cost of service. The Company argues that the cost of transmission is offset by the lower gas reservation costs.
>
> The cost of transmission to move energy from Crossroads to customers served by MPS is a very significant cost that is far greater than the transmission cost for power plants located in the MPS district. The annual energy transmission cost was estimated as $406,000 per month. This is also substantially higher on an annual basis than the transmission plant costs for the Aries site where the three South Harper Turbines were originally planned to be installed.
>
> This higher transmission cost is an ongoing cost that will be paid every year that Crossroads is operating to provide electricity to customers located in and about Kansas City, Missouri. GMO does not incur any transmission costs for its other production facilities that are located in its MPS district that are used to serve its native load customers in that district. **This ongoing transmission cost GMO incurs for Crossroads is a cost that it does not incur for South Harper, and is the cause of one of the biggest differences in the on-going operating costs between the two facilities.**
>
> It is not just and reasonable to require ratepayers to pay for the added transmission costs of electricity generated so far away in a transmission constricted location. Thus, the Commission will exclude the excessive transmission costs from recovery in rates.
> [Emphasis added]

The adjustment to remove the Crossroads transmission costs from the test year is E-82.2 in Staff's Accounting Schedule 10. Staff witness Karen Lyons also addresses other adjustments for transmission expenses for MISO administrative costs related to Crossroads in the transmission costs section of this report.

continued on next page

GMO's annual total of transmission costs for Crossroads by year from 2007 through 2015 are:

2015	** __________ **
2014	** __________ **
2013	** __________ **
2012	** __________ **
2011	** __________ **
2010	** __________ **
2009	** __________ **
2008	** __________ **
2007	** __________ **

[Response to Data Request No. 0154 in Case No. ER-2012-0175 and Data Request No. 0155.1S, 160 and 167.3S in Case No. ER-2016-0156]

The Commission noted at page 58 of the Findings of Fact section of the Order in Case No. ER-2012-0175:

> 1. Crossroads is 500 miles from GMO's MPS territory.
>
> 2. Between the territory of MPS and Crossroads are the territories of regional transmission organizations ("RTOs"). RTOs collect payment for the transmission of power through their territories. GMO does not belong to all those RTOs so GMO must pay higher fees for transporting power than to an RTO of which GMO is a member.
>
> 3. There are generating facilities closer, including Dogwood's facility and the South Harper plant. Even though Crossroads provides power for GMO only during half of the days in the summer, GMO pays about $5.2 million to transmit power from Crossroads all year round. The high cost of transmission is not outweighed by lower fuel costs in Mississippi.

NP

Discussion, Conclusion of Law, and Ruling

> **GMO has not carried its burden of proof on transmission costs.** GMO alleges that the lower price of fuel in Mississippi outweighs the cost of transmission. The Commission has found that the evidence preponderates otherwise.
>
> ....
>
> Therefore, the Commission concludes that including the Crossroads transmission costs does not support safe and adequate service at just and reasonable rates, and the Commission will deny those costs.
> [page 59 of Order in Case No. ER-2012-0175; emphasis added]

The Commission's Order in both the 2010 and 2012 rate cases prohibited GMO from any recovery of transmission costs related to Crossroads. The Commission stated at page 64 of its 2012 Order with respect to the recovery of Crossroads transmission costs:

> Crossroads Transmission. Several parties ask the Commission to order that GMO's FAC tariff sheets state expressly that GMO's FAC excludes transmission costs related to Crossroads. Insofar as the Commission has determined that no transmission costs from Crossroads will enter GMO's MPS rates, there is no further dispute, and no further findings of fact and conclusion of law are required. The Commission will order GMO's FAC clarified to stat that GMO's FAC excludes transmission costs related to Crossroads.

While considering the Commission's decision not allowing recovery of Crossroads transmission costs in rates, either in base rates or through the fuel clause, Staff became aware in this proceeding that some Crossroads-related transmission costs had been inappropriately recovered by GMO through the fuel clause. Staff then investigated this matter further with GMO.

As a result, GMO is proposing in its current FAC filing with the Commission to credit to customers electric bills an amount for the Crossroads transmission costs that should not have been previously collected in rates. Staff witness Matthew Barnes addresses the refunding of these amounts through the fuel clause in another section of Staff's Cost of Service Report.

Consistent with the Commission's decision in last two GMO rate cases, Staff excluded all Crossroads transmission costs in this current case. Staff continues to recommend that GMO not be allowed any recovery of transmission costs associated with Crossroads either in base rates or through the fuel clause. This generating facility is over 500 miles from the service area of GMO. The transmission constraints where Crossroads is located were the reason why this power plant was installed in Mississippi. The transmission constraints and distance of this facility from GMO's customers results in the extremely high transmission costs resulting from this plant's operations.

Crossroads has seen a dramatic increase in transmission costs in 2014 and 2015, since Entergy joined the MISO RTO in December 2013. GMO customers should not have to pay for any portion of those costs as it was imprudent for this plant to be located where it is. If this merchant peaking plant had been properly located as other peaking units, there would be no additional transmission costs to operate the plant. No other generating unit in KCPL's or GMO's fleet is in another RTO and no other generating unit incurs transmission costs to transport its power to GMO's customers.

Crossroads, constructed in 2002 as a non-regulated merchant plant, was never contemplated to be used as a regulated generating facility and certainly never was designed to serve electric loads over 500 miles from the location of the generating facility It is the location of this generating facility in relation to the customers' electric needs that makes Crossroads imprudent. Accordingly, disallowance of Crossroads transmission costs is not a "transmission" issue as GMO would lead the Commission to believe, but rather the direct outcome of the placement of this power plant that has resulted in the tremendous costs to operate the plant. Once the generating unit could not be sold when it was determined to no longer be necessary to Aquila Merchant's non-regulated business model, it was then a power plant operating in a distressed market having very limited value to any regulated entity.

It is imprudent for GMO to attempt to charge its customers for having a power plant located in Mississippi to serve western Missouri customers. It is therefore also imprudent to allow recovery of the excessive transmission costs to operate this power plant facility. In the 2010 and 2012 rate cases, the Commission deemed Crossroads prudent as long as customers did not have to pay the purchase price when the facility was built by Aquila Merchant and as long as customers did not have to pay for the transmission costs associated with a very constrained transmission system and transmitting power through a non-SPP regional transmission organization. These decisions are still appropriate today in the context of this rate proceeding.

Staff Expert/Witness: Cary G. Featherstone

C. Stipulation and Agreement in Case No. ER-2012-0175

In GMO's last rate case, it agreed to reduce transmission and distribution plant through a series of adjustments to increase depreciation reserve. At page 12, under the GMO Only Issues in the *Non-Unanimous Stipulation and Agreement As To Certain Issues*, the following appears as item 3:

> 3. Transmission and Distribution Plant: Upon Commission approval of this Stipulation GMO will reduce its transmission and distribution plant rate base by a total of $8.0 million, 65% for MPS and 35% for L&P, to be reflected in Staff's and Company's models for the true-up in this cases. GMO agrees it will not request recovery of this reduction by any means, directly or indirectly, in the future. GMO will provide to Staff plant accounting records that identify exclusion of these amounts from future rate base consideration.

Transmission & Distribution Plant				
FERC USOA Account Number & Description				
		MPS	L&P	Total
355	Transmission– Poles & Fixtures	$628,874	$775,306	$1,402,180
356	Transmission- Cond & Devices	$1,196,710	$2,024,694	$3,221,405
365	Distribution- OH Conductor	$3,055,085		$3,055,085
366	Distribution- UG Circuit	$321,331		$321,331
	Total	$5,200,000	$2,800,000	$8,000,000

Both GMO and Staff made these adjustments to reflect the agreement reached in Case No. ER-2012-0175. The Adjustments are R-288, R-290, R-305 and R-307.

Staff Expert/Witness: Cary G. Featherstone

D. Plant Amortization

Staff evaluated and annualized GMO's plant amortization expense. Plant amortization expense represents elements such as the use of software, land rights and other intangible items that are not included in the depreciation expense schedule in Staff's EMS Cost of Service schedules.

The disallowance for the Crossroads plant was calculated pursuant to the Commission's *Report and Order* in Case Nos. ER-2010-0356 and ER-2012-0175. Staff witness Cary G. Featherstone identifies these adjustments in his portion of this report. A portion of the Crossroads ordered disallowance is an intangible amortizable plant amount. The annual amount of plant amortization related to this portion of the Crossroads plant disallowance has not been included in the annualized amount, pursuant to the Commission's *Report and Order*. Staff's adjustments are identified on Schedule 9 of Staff's GMO consolidated, MPS and L&P Accounting Schedules, Adjustments E-174.1 and E-176.1.

Staff Expert/Witness: Michael Jason Taylor

E. Construction Audit of Jeffrey SCR Project Cost

1. Physical description of project

Jeffrey Energy Center ("JEC") is a generating plant located near St. Marys, Kansas. Composed of three 800 MW subcritical, pulverized coal-fired generating units, it is operated by the majority owner, Westar Energy, Inc., with GMO, owning 8% of the plant.

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Staff has reviewed two recent construction activities related to the reduction of NOx at JEC, a Selective catalytic reduction system ("SCR") on Unit 1 and a Selective non-catalytic reduction system ("SNCR") on Unit 2. The major components associated with the Nitrogen Oxides Reduction project on Unit 1 include:

- Selective catalytic reduction system,
- ** ________________________________ **
- Ammonia storage and supply system,
- Four induced draft fans with variable frequency drives,
- Main auxiliary power transformer, and
- ** ________________________________ **

** ____

______ **

- SmartBurn® system, ** ______________________________
  ______________________________ **
- Selective non-catalytic reduction system.

SCR is a process for controlling NOx emissions by the reduction of NOx to nitrogen and water vapor. A nitrogen based reagent (ammonia or urea) is injected into the flue gas stream. The flue gas mixes with the reagent and enters a reactor containing a catalyst element. The reagent reacts with the NOx in the presence of the catalyst and oxygen to form nitrogen and water vapor.

** ____

____ **

In addition to the SCR, the project included the following major components:

** ____

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d. **Operational impacts**

** [59] **

Jeffery Energy Center Unit 1 Performance Estimates

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[59] Information provided by KCPL in response to Staff Data Request No. 0029 in Docket No. EO-2014-0043.

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e. Recommendations Concerning Decision to Undertake the Project

The decision to undertake the Nitrogen Oxides Reduction Projects was primarily based on the 2010 Consent Decree between the EPA, the State of Kansas, and Westar. The Consent Decree requires Westar to install a SCR on one of the three unit JEC units by December 31, 2014, and to decide whether to install a second SCR on another JEC unit. The consent decree also requires Westar to evaluate installation of a SNCR. The consent decree allows Westar to elect not to install a second SCR provided they meet a plant wide thirty-day rolling average NOx emissions levels of 0.100 lb/MMBtu or less, with annual total emissions less than 9,600 tons. The EPA required Westar to notify it of Westar's decision to or not to install a second SCR or a SNCR by December 31, 2012. **

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f. In-Service

To reflect the Unit 1 SCR and Unit 2 SNCR in rates, the Commission must determine that the emission control equipment is "fully operational and used for service."[60] In-service criteria are a set of operational tests or operational requirements that Staff relies on to make a recommendation to the commission regarding whether a new unit, or in this instance, emissions control equipment is "fully operational and used for service." Operational tests are established

[60] Section 393.135, RSMo. 2000: "Any charge made or demanded by an electrical corporation for service, or in connection therewith, which is based on the costs of construction in progress upon any existing or new facility of the electrical corporation, or any other cost associated with owning, operating, maintaining, or financing any property before it is fully operational and used for service, is unjust and unreasonable, and is prohibited." (Emphasis added).

and performed in order for Staff to file its recommendation. The Staff develops its criteria, based on its review of the engineering specifications and discussions with the Company. The Company and Staff agreed upon the in-service criteria for the Jeffrey Unit 1 SCR, included in Appendix, Schedule DIB-d1 and in the Direct Testimony of Tim Rush as schedule TMR-9.

Based on Staff's evaluation of the data and inspection of the facility, detailed in Appendix 3, Schedule DIB-d1, the Jeffery Energy Center Unit 1 SCR has met all of the required in-service criteria effective March 21, 2015. Therefore, Staff recommends that the Jeffery Energy Center Unit 1 SCR be considered fully operational and used for service in setting rates in this case.

Staff did not utilize specific in-service criteria for the Jeffrey Unit 2 SNCR project due to the small scope of the overall project and GMO's share of the project. Rather than utilizing specific in-service criteria, Staff reviewed the SNCR performance testing which was completed as part of the SNCR contract and provided in response to Staff Data Request No. 0027.1 in EO-2014-0043. Additionally, Staff reviewed data[61] which demonstrates that JEC has met a plant-wide, thirty-day rolling average NOx emissions levels of 0.100 lb/MMBtu or less, consistent with annual total emissions less than 9,600 tons.

Based on Staff's evaluation of the data, the Jeffery Energy Center Unit 2 SNCR completed performance testing effective October 30, 2014.[62] Therefore, Staff recommends that the Jeffery Energy Center Unit 2 SNCR be considered to have been fully operational and used for service as of October 30, 2014.

Staff Expert/Witness: Daniel I. Beck, PE

2. <u>Audit of Jeffrey SCR Project</u>

Staff has reviewed the construction costs of the Jeffrey SCR and is satisfied that these units were properly accounted for in the Company's plant in service records and properly included in rate base investment. Based upon its audit, Staff does not have any concerns that the construction costs for this project were imprudently incurred and recommends that the final cost of the SCR and its related equipment should be included in rate base at the values that GMO currently has recorded in its plant records.

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[61] Information provided by KCPL in response to Staff Data Request No. 0310 in ER-2016-0156.
[62] Information provided by KCPL in response to Staff Data Request No. 0365 in ER-2016-0156.

Staff submitted data requests requesting information and copies of documents regarding authorizations, construction budgets, construction costs and change orders for the Jeffrey SCR project. Once Staff received this information, Staff submitted follow-up questions, by either data request or e-mail, to KCPL personnel (working on behalf of GMO) assigned to the construction cost review as facilitators to Staff.

Staff reviewed the following documents, among others, to establish its conclusions concerning the Jeffrey SCR Project:

- Reports to the Executive Oversight Committee ("EOC") of the Great Plains Energy Board of Directors. These reports provided a high level monthly review of significant issues, budget, and forecast at completion relating to the Jeffrey SCR.
- Reports to the Board of Directors, similar to the EOC reports.
- Internal and external audits performed by or on behalf of Westar related to the Jeffrey SCR project.
- Burns & McDonnell Monthly Progress Reports for the duration of the project. These reports prepared by Westar's engineer provided detailed information on project status, budget and actual costs, schedule performance, and change orders.
- Budget and actual cost tracking documents for the duration of the project.

Staff reviewed documentation provided through the Commission's EFIS system, physical copies, and CDs. In addition, Staff reviewed documents at KCPL's headquarters in Kansas City, Missouri that were determined to be "on site" review only.

The Jeffrey SCR project was completed under budget, and on schedule. The "Conceptual Estimate" for the Jeffrey SCR project was established at ** ____________ **, not including GMO's Allowance for Funds Used During Construction ("AFUDC"). AFUDC is the construction cost component equal to the financing cost associated with amounts invested in the project, and is calculated by GMO independently from Westar. The final cost at completion is ** ____________ **, not including AFUDC, and excluding any remaining contingency amounts that will not be expended. GMO's share of the total project costs is 8%.

Staff recommends the cost of the Jeffrey SCR project be included in GMO's regulated rate base in this case. For Staff's direct filing, the plant balance to be included in rate base along with the accumulated depreciation reserve values is as of December 31, 2015. Staff will update

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these amounts to the July 31, 2016 values during the true-up audit along with all other items of plant and depreciation reserve. The depreciation reserve values in Staff's case for the Jeffrey SCR reflect the depreciation that has accumulated since the time GMO has included this item in plant in service.

Staff Expert/Witness: Keith Majors

F. Greenwood Solar Project

On November 12, 2015, GMO filed an application, Case No. EA-2015-0256, with the Commission requesting permission and approval of a Certificate of Public Convenience and Necessity ("CCN") authorizing it to construct, install, own, operate, maintain and otherwise control and manage solar generation facilities in Greenwood Missouri ("Greenwood Solar Project"). GMO entered into a Master Service Agreement ("Agreement") with ** ________ ____________________ ** for the engineering, procurement, and construction of the Greenwood Solar Project.[63] The Greenwood Solar Project is a 3 megawatts ("MW") solar facility that will produce approximately 4,700 megawatt-hours ("MWh") of solar energy per year.[64] GMO indicated in its certificate application the Greenwood Solar project was being proposed to gain experience owning, maintaining, and operating a utility scale solar facility.

The Commission approved GMO's request for a CCN for the Greenwood Solar Project in its *Report and Order* effective March 12, 2016. On page 18 of its *Report and Order*, the Commission stated, "The Commission has found that GMO's proposal to construct a pilot solar plant is necessary or convenient for the public service and will grant the company the certificate of convenience and necessity it seeks."

In addition to granting GMO the CCN for the Greenwood Solar Project, the Commission also addressed concern that GMO ratepayers will bear all the costs of a project that is primarily being built to allow KCPL to gain experience owning, maintaining, and operating a utility scale solar facility. Beginning on page 16 of its *Report and Order* in Case No. EA-2015-0256, the Commission stated:

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[63] KCPL-GMO response to Staff Data Request No. 0006 in Case No. EA-2015-0256.

[64] *Application of KCP&L Greater Missouri Operations Company for Permission and Approval of a Certificate of Public Convenience and Necessity Authorizing It to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage Solar Generation Facilities in Western Missouri*, Page 3.

> The Commission is concerned that only GMO ratepayers will bear the cost of the project. The Commission will not make any specific ratemaking decisions in this case. Those will be reserved for GMO's pending rate case. However, the matter will once again come before the Commission when GMO seeks to add the plant to its rate base. **At that time, the Commission will expect GMO to propose a means by which those costs will be shared with KCP&L's customers who will also benefit from the lessons learned from this pilot project.** (Emphasis added.)

GMO does not have any employees. KCPL employees perform all services for Great Plains, KCPL and GMO under an operating agreement. The employees that will gain the experience operating a utility scale solar project are KCPL employees. Consequently, all rate districts, KCPL-Missouri, KCPL-Kansas, and GMO, will benefit from the acquired knowledge from building and operating a utility scale solar facility.

GMO anticipates that the Greenwood Solar Project will achieve its in-service requirements in early July 2016. If the in-service criteria are met, the costs of the solar project will be included in GMO's cost of service in the true-up phase of this case. At this time the budgeted total cost of the Greenwood Solar Facility is $7,472,852.[65] Since the actual costs of the solar project are not known and the in-service criteria have not been met, the solar project costs are not included in Staff's Accounting Schedules for its direct filing in this case. Staff witness Daniel I. Beck will address the in-service criteria for the solar facility in true-up.

As no proposal to allocate the Greenwood Solar Project costs were made by GMO in its direct filing in this case, in contradiction to the Commission *Report and Order* in Case No. EA-2015-0256, Staff is proposing an allocation methodology for the Greenwood Solar Project costs that will be included in GMO's cost of service in the true-up phase of this case.

During the discovery process in this case, Staff asked GMO how the solar project's costs would be allocated if the rates for MPS and L&P rate districts were ultimately not consolidated as proposed by GMO and Staff in this case. GMO responded stating that the capital costs and expenses would be allocated based on an energy allocator using 2015 MWh's.[66] Staff recommends allocating the Greenwood solar project costs and any related revenues based on an energy allocator using 2015 MWh's of KCPL and GMO. If the Commission does not approve

[65] KCPL-GMO response to Staff Data Request No. 0197.1 in Case No. ER-2016-0156.
[66] KCPL-GMO response to Staff Data Request No. 0197 in Case No. ER-2016-0156.

consolidating MPS and L&P rates in this case, Staff supports a further allocation between those two entities. Since the Greenwood Solar Project is being built to gain experience owning, operating, and maintaining a utility scale solar facility with KCPL employees gaining the experience, Staff also recommends that the costs of the Greenwood Solar project be allocated to KCPL and its jurisdictions. This can be accomplished using the same methodology in KCPL's rate case currently filed with the Commission, ER-2016-0285, using an energy allocator.

While Staff is recommending allocating the costs of the Greenwood Solar Project based on an energy allocator, Staff is open to discussion for alternative allocation methodologies from other parties in this case.

Staff Expert/Witness: Karen Lyons

G. Material and Supplies

Staff's recommended treatment of materials and supplies is to examine each account individually in order to determine an appropriate level that most accurately reflects the ongoing future expense of a particular account. Materials and supplies represent an investment in inventory for relatively small-dollar items such as spare parts, electric cables, poles, meters, and other miscellaneous items used in daily operations and maintenance activities by GMO to maintain GMO's production facilities and electric systems.

GMO's account balances varied greatly depending on each individual account. Staff reviewed the balances for each account for materials and supplies individually on a monthly basis to determine whether trends within an individual account existed over time. Staff reviewed the monthly balances for materials and supplies accounts from June 2014 to December 2015. If an upward or downward trend was detected, then Staff used the ending balance for that account. If there was no discernible trend, then an average of the accounts was used, typically a 13-month average, to determine the most appropriate measure of the ongoing investment level. Staff examined the accounts individually and determined which methodology, an average or ending balance, was the most appropriate measure to accurately predict the ongoing future of a particular account and included the level in Staff's GMO consolidated rate base Accounting Schedule 2.

Staff Expert/Witness: Sean M. Cahoon

H. Prepayments

Prepayments are the costs a company incurs and pays in advance. As an example, GMO buys property insurance to protect its assets, the costs of which are treated as a prepayment. Prepayments are treated as an asset and are reflected in the utility's rate base. Staff included amounts in its rate base for all prepayments that GMO requires to provide electric utility service to its customers.

Staff's recommended treatment of prepayments is to deduct the jurisdictional amount of the 13-month average ending December 31, 2015, of prepayments from GMO's consolidated rate base. A 13-month average was used because the account balances varied month to month and did not exhibit a discernible upward or downward trend. Each prepayment account was examined individually in order to determine an appropriate measure that most accurately predicts the ongoing future expense of a particular prepayment account and then included in GMO's rate base. Staff examined all of GMO's prepayment account balances dating back to GMO's previous rate case (ER-2012-0175) through December 2015, on a month-by-month basis (Accounting Schedule 2).

Staff Expert/Witness: Sean M. Cahoon

I. Cash Working Capital

Cash Working Capital ("CWC") is the amount of cash necessary for a utility to pay its day-to-day expenses incurred in order to provide utility services to its customers. When a company expends funds to pay an expense before its customers provide the cash, then a "lag" exists and the shareholders are the source of the funds. This cash represents a portion of the shareholders' total investment in the utility. The shareholders are compensated for the CWC funds they provide by the inclusion of these funds in rate base. By including these funds in rate base, the shareholders earn a return on the funds they have invested. Conversely, customers supply CWC when they pay for electric services received before a company pays expenses incurred to provide that service. When such a "lead" exists, utility customers are compensated for the CWC they provide by a reduction to the utility's rate base.

A positive CWC requirement indicates that, in the aggregate, the shareholders provided the CWC for the test year. This means that, on average, the utility paid the expenses incurred to provide the electric services to its customers before those customers had to pay the Company for the provision of these utility services. A negative CWC requirement indicates that, in the aggregate, the utility's customers provided the CWC for the test year. This means that, on average, the customers paid for the utility's electric services before the utility paid the expenses that the utility incurred to provide those services.

Staff reviewed the revenue and expense lags used by GMO, as described by GMO witness Ronald A. Klote (Direct Testimony, pages 26-28). GMO included updated values for the retail revenue and blended total revenue lag factors, the ratio of accounts receivable factored, and the number of days that bills were outstanding. GMO used the MPS and L&P rate districts' expense lags agreed to in Case No. ER-2012-0175. In Staff's CWC analysis, the exceptions to the carryover of expense lags approved in GMO's last case are the expense lag for corporate franchise tax and the addition of incentive compensation to the CWC analysis. As discussed by Staff Witness Keith Majors, federal corporate franchise taxes were completely repealed as of January 2016. Consequently, Staff has removed the corporate franchise tax from its CWC schedule. Otherwise, Staff adopted GMO's CWC and mirrored its methodology to consolidate the CWC schedules for GMO's MPS and L&P rate districts. If there was an inconsistency between the two rate districts the expense lag for MPS was used. If the Commission approves Staff's recommendation to consolidate GMO's MPS and L&P rate districts, Staff will review GMO's CWC in the next rate case when consolidated data will be available for a comprehensive lead/lag study.

The Cash Working Capital Schedule, Accounting Schedule 8, identifies the amount of cash working capital to be reflected in GMO's cost of service. The results of Staff's CWC analysis are reflected on the Rate Base - Accounting Schedule 2 in several places. The CWC analysis results, excepting the CWC impacts of income taxes and interest expense, can be found in the Rate Base schedule section "Add to Net Plant In Service." Staff's CWC analysis results for federal taxes, state taxes, city taxes and interest expense can be found in the Rate Base schedule section titled "Subtract From Net Plant."

Staff Expert/Witness: Matthew R. Young

J. Fuel Inventories

1. Coal Inventory

The amount Staff included in GMO's rate base for coal inventory is based on the results obtained from Staff's production cost model ("fuel model"). Staff used its fuel model to determine the appropriate mix of generation unit and purchased power utilization to match the normalized native load for GMO. In doing so, Staff obtained from the fuel model an annual amount of tons of coal burned by each coal-fired generation unit during the normalized updated test year. Staff divided the annual tons of coal burned from the fuel model by 365 days to calculate an average daily burn by unit. Staff then multiplied this average daily burn by GMO's recommended number of burn days of coal inventory for each generation unit and added an estimated level of basemat coal. Basemat coal is the bottom portion of the coal pile that is difficult to burn in the generating facilities because of the contamination of moisture, soil, clay, and other contaminants. Staff then multiplied the resulting normalized level of inventory for each unit by the delivered cost per ton of coal for use at that unit. The resulting annual coal costs for each unit were then aggregated. The aggregated amount was multiplied by Staff's energy jurisdictional allocation factor to arrive at the coal inventory amount shown in Staff's GMO consolidated and MPS and L&P accounting schedules in Rate Base – Schedule 2.

Staff Expert/Witness: Karen Lyons

2. Oil and Fuel Additive Inventories

Staff used 13-month averages to determine the inventory levels for oil, lime, limestone, ammonia, propane, urea, and powder activated carbon inventories as of December 31, 2015. Staff priced out the various inventories using the latest pricing or the actual monthly dollar levels of inventory. Use of 13-month average inventory levels is appropriate in that it reflects GMO's actual experience for the entire 12-month test year period by including a beginning inventory and an ending inventory. For example, if the test year were a calendar year it would begin with January 1 and end with December 31. A 13-month average reflects the entire year by using the December 31 (January 1) beginning balance and including each subsequent month-ending balance through the end of the year (December 31). When inventory levels fluctuate from month-to-month, as they do with fuel stocks, a 13-month average is used to smooth out those levels. Staff's inventory levels for oil, lime, limestone, ammonia, propane, urea, and powder activated carbon are shown in Staff's GMO consolidated and MPS and L&P accounting schedules in Rate Base – Schedule 2.

Staff Expert/Witness: Karen Lyons

K. Customer Deposits

Staff's recommended treatment of customer deposits is to deduct the jurisdictional amount of the 13-month average of customer deposit balances ending December 31, 2015, from GMO's consolidated rate base (Accounting Schedule 2, Rate Base). A 13-month average was used because the account balances varied month to month and did not exhibit a discernible upward or downward trend.

Customer deposits are the funds required to be provided by certain GMO customers based on the existence of certain conditions. These conditions include the following: (1) The service of the customer has been discontinued by GMO for nonpayment of a delinquent account not in dispute; (2) The customer has failed to pay an undisputed bill before the delinquency date for two billing periods during the past year or has a had a payment returned for any reason other than bank error; (3) The customer has in an unauthorized manner interfered with or diverted the electrical service received from GMO; (4) The customer has an unsatisfactory credit rating from a financial institution or credit rating agency commonly recognized in the financial community, or has filed a petition for bankruptcy during the previous seven years; (5) Misrepresentation of identity for the purpose of obtaining utility service; (6) GMO has become aware through a public medium that the customer is experiencing financial difficulties; or (7) GMO is requiring a security deposit or other guarantee as a condition of service to any customer at a new or existing location as provided in 4 CSR 240-13 030.

Customer deposits are deducted from GMO's rate base because these funds are cost-free funds received by GMO and are not related to the respective customers' electrical service use. In addition to the amount deducted from rate base for customer deposits, an amount for interest on customer deposits has been included as an adjustment to the income statement under Account 903 (Accounting Schedule 9). Customers are paid interest for the use of the funds they provide to GMO on a cost-free basis since these funds are not related to customer consumption, and that interest expense is included as an expense in the revenue requirement calculation as discussed in more detail in the "Customer Deposits – Interest Expense" section below. The Commission should base its awarded revenue requirement on Staff's recommended deduction of a 13-month average of balances for Customer Deposit funds reflected in the GMO consolidated rate base.

Staff Expert/Witness: Sean M. Cahoon

L. Customer Advances

Staff's recommended treatment of customer advances for the GMO consolidated rate district is to deduct a 13-month average of account balances ending December 31, 2015, from its rate base, as the monthly account balances for GMO did not exhibit a discernible upward or downward trend.

Customer advances are funds typically provided by construction developers to GMO in order to ensure that GMO builds electric infrastructure in areas that have potential for future development. These advances are also used by the utility to establish electric service for potential future customers without investing a substantial amount of money at the risk of the utility and its other customers. Unlike customer deposits, where GMO receives these payments from respective customers on a cost-free basis without any future obligation to provide electrical service to those customers, customer advances are provided to GMO from certain customers that obligate GMO to provide future electrical infrastructure and service for those affected customers. Customer advances represent a recorded liability to recognize the obligation to eventually return the funds advanced by customers to GMO. The infrastructure constructed with these funds is not financed with debt or equity and, thus, ratepayers should not be obligated to pay a return on these plant investments. Thus, customer advances are included in the rate base as a reduction, lowering the amount of overall investment that customers must supply as a return to the utility (Accounting Schedule 2).

Staff Expert/Witness: Sean M. Cahoon

M. Iatan Construction Accounting Regulatory Assets

The Iatan Construction Accounting Regulatory Assets are the result of various agreements approved by the Commission. Below is a table identifying the applicable generating unit, time period, expense type, and governing document as approved by the Commission:

Owner	Generating Unit	Expense Type	Accumulation Period	Authorization
GMO – MPS and L&P	Iatan 1 and Common	Depreciation, Carrying Cost, No O&M	May 1, 2009 - June 25, 2011	ER-2009-0090 Stipulation
GMO – MPS and L&P	Iatan 2	Depreciation, Carrying Cost, O&M	August 26, 2010 - June 25, 2011	Accounting Authority Order EU-2011-0034

Pursuant to the terms of the *Non-Unanimous Stipulation and Agreement* approved by the Commission on June 10, 2009, in Case No. ER-2009-0090, GMO was authorized to create a regulatory asset for the depreciation and carrying costs ("construction accounting") for the Iatan Unit 1 Air Quality Control System and Iatan Common Plant that was not included in GMO's rate base in that case. The Commission also authorized GMO to record in an account the depreciation, carrying costs, and other operating expenses and credits for Iatan Unit 2 subsequent to its commercial in-service date of August 26, 2010, pursuant to its *Order Granting Accounting Authority Order* on September 28, 2010 in Case No. EU-2011-0034.

For purposes of inclusion in rate base, Staff reflected the balances of these regulatory asset accounts as of December 31, 2015, the end of the test year update period the Commission ordered in its March 16, 2016, procedural schedule Order in this case, ER-2016-0156.

The Iatan Unit 1 and common regulatory assets capturing construction accounting from May 1, 2009, through December 31, 2010, the true-up cutoff in Case No. ER-2010-0356, are referred to as "Vintage 1." These regulatory assets are included in Rate Base – Schedule 2 and are amortized over 27 years as established in that case. The Iatan Unit 1 and common regulatory assets capturing construction accounting from January 1, 2011, through June 25, 2011, the effective date of rates in Case No. ER-2010-0356, are referred to as "Vintage 2." These regulatory assets are included in Rate Base – Schedule 2 and amortized to expense over 25.4 years, or, the 27 years reduced by the number of months since the effective date of rates in Case No. ER-2010-0356.

The Iatan Unit 2 regulatory asset capturing construction accounting from August 26, 2010, through December 31, 2010, the true-up cutoff in Case No. ER-2010-0356, is referred to as "Vintage 1." This regulatory asset is included in Rate Base – Schedule 2 and is amortized over 47.7 years as authorized by the Commission in that case. The Iatan Unit 2 regulatory asset capturing construction accounting from January 1, 2011, through June 25, 2011, the effective date of rates in Case No. ER-2010-0356, is referred to as "Vintage 2." This regulatory asset is included in Rate Base – Schedule 2 and amortized to expense over 46.1 years, or, the 47.7 years as authorized by the Commission reduced by the number of months since the effective date of rates in Case No. ER-2010-0356.

The test year ending June 30, 2015, includes a full 12 months of amortization related to these regulatory assets; therefore, no adjustment to expense is necessary.

Staff Expert/Witness: Keith Majors

VII. Income Statement – Revenues

A. Rate Revenues

1. Introduction

Rate Revenue: Test year and update period rate revenues consist the revenues derived from GMO's charges for sales of electric service to its Missouri retail customers for the 12-months ending June 2015 and updated through the end of December 2015. While considered elsewhere, rate revenues do not include miscellaneous revenues such as those associated with late payment fees or service extension costs. GMO's rate revenues are determined by each customer's usage and the (per unit) rates that are applied to that usage. Different rates apply to different times of the year (summer vs. winter); different types of charges (demand, energy); and to customers in different rate classes.

Staff Expert/Witness: Robin Kliethermes

2. The Development of Normalized and Annualized Usage and Revenue in this Case Rate Revenue

The normalized and annualized usages and revenues developed by Staff serve three purposes in each rate case. The first purpose is to determine the normalized and annualized level of revenue that is generated by existing tariffs. The second purpose is for the development of Net System Input ("NSI") for the calculation of variable fuel and purchased power expenses. Finally, normalized and annualized usage is also used with the ordered revenue requirement resulting from a case to determine the appropriate value for each rate element to be included in the compliance tariff sheets. This latter usage is commonly referred to as billing determinants.

GMO's total-company cost of service has historically been allocated or assigned between two rate districts, MPS and L&P. In this case, Staff recommends discontinuation of the practice of allocating or assigning GMO's cost of service to separate rate districts. For example, GMO's current tariff contains a different set of rate schedules for residential customers in the MPS rate district and residential customers in the L&P rate district. In this case, Staff will recommend that all residential customers in the GMO service territory be served on one set of residential rate schedules.[67] However, because there are currently two rate districts with two sets of residential rates, in order to determine the level of GMO companywide rate revenues and normalized and annualized usage, Staff has applied standard ratemaking adjustments to usage (kWh) and revenue data for both MPS and L&P rate districts separately. Staff added the normalized and annualized usage and revenue results for the MPS and L&P rate districts together for GMO companywide rate revenue and usage totals.[68]

The intent of usage and revenue adjustments to test year and update period Missouri rate revenues is to determine the level of revenue that the Company would have collected from the customers in each service area on an annual basis, under normal-weather or climatic conditions, based on information "known and measurable" by the end of the update period. The Rate Revenue Summary Tab of Staff's Accounting Schedules summarizes rate revenue by type of adjustment and by total rate revenues per rate class. The rate classes shown for GMO for each currently-existing rate jurisdiction are Residential ("RES"), Small General Service ("SGS"), Large General Service ("LGS"), Large Power Service ("LPS"), Special, and Lighting. Staff workpapers provide the source numbers and analysis for the individual rate codes, and present a much more detailed version of the summary table.

This report briefly describes seven adjustments that Staff made to test year and update period billed rate revenues:

a. weather normalization & 365 - day adjustment

b. customer growth

[67] While the residential class is the subject of this example, Staff will be recommending consolidation of rates for all classes.

[68] As will be discussed in greater detail in Staff's Report on Class Cost of Service and Rate Design, additional analysis is necessary to develop billing determinants for total-company rates.

c. large customer annualizations

d. customer discounts

Not all adjustments affect both usage and rate revenue. Not all rate classes are subject to all five adjustments.

Staff Expert/Witness: Robin Kliethermes

3. Weather Normalization

a. Weather Variables

This information was provided to Staff witness Seoung Joun Won for weather normalization of the kWh usage and hourly loads. Each year's weather is unique; consequently, test year usage, hourly loads, revenue, and fuel and purchased power expense need to be adjusted to "normal" weather patterns so that rates will be designed on the basis of normal weather rather than any anomalous weather in the test year.

Source of Weather Data – In the quantification of the relationship between test year weather and energy sales, Staff used weather observations of the Kansas City International Airport ("MCI") in Kansas City, Missouri, for the test year, July 1, 2014, through June 30, 2015.

As a measure of "normal" weather, Staff used a 30-year period of "climate normals" ("normals") by the National Climatic Data Center ("NCDC") of the U.S. National Oceanic and Atmospheric Administration ("NOAA"). According to NOAA, a climate normal is defined as the arithmetic mean of a climatological element computed over three consecutive decades.[69] To conform to the NOAA's three consecutive decades for determining normal temperatures, Staff used observed maximum and minimum daily temperatures for the 30-year period of January 1, 1981, through December 31, 2010. Therefore, Staff bases its calculations on the time period of the most recent climate normals produced by NCDC. [70]

Although the definition of normal weather is relatively simple, the actual calculations may be more complicated. Inconsistencies and biases in the 30-year time series of daily temperature observations occur if weather instruments are relocated, replaced, or recalibrated. Changes in observation procedures or in an instrument's environment may also occur during the

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[69] Retrieved on January 27, 2016, http://www ncdc noaa.gov/data-access/land-based-station-data/land-based-datasets/climate-normals.

[70] Retrieved on January 27, 2016, http://www ncdc noaa.gov/data-access/land-based-station-data/land-based-datasets/climate-normals/1981-2010-normals-data.

30-year period. NOAA accounted for these anomalies in calculating the normal temperatures it published in July 2011.

Staff verified the adjustments for anomalies in the MCI time series by direct communication with NCDC, and through Staff's own review of the daily observations. According to NCDC, the serially-complete monthly minimum and maximum temperature data sets have been adjusted to remove all inconsistencies and biases due to changes in the associated historical database. Furthermore, Staff's review of NCDC's peer-reviewed, published paper[71] that explains the accuracy of the NCDC's monthly temperature series homogenization procedure for removing documented and undocumented anomalies, and found it to be meteorologically and statistically sound.

Because Staff uses daily temperature observations to calculate normal weather values and NOAA's normals are monthly values, Staff adjusted the observed daily temperatures so that the monthly average temperature calculated from these adjusted daily values is the same as the NCDC's serially-complete monthly temperature time series. Staff derived the daily mean temperature time series, daily two-day weighted mean temperatures, and normal daily temperatures from these adjusted daily temperatures.

Definition of Weather Variables - Because weather fluctuates greatly from day-to-day, the MCI temperature variables required to weather-normalize sales are two-day weighted daily mean temperatures of the update period actual and the 30-year normal. The day's daily mean temperature is generally defined as the simple average of the day's maximum daily temperature and minimum daily temperature. The daily two-day weighted mean temperature is calculated using the previous day's mean daily temperature with a one-third weight and the current day's mean daily temperature with a two-thirds weight.[72]

This was done because yesterday's weather effects how electricity is used today in the GMO service area. This is likely due to heat retention by the structures in the service area. For example, if today's temperature is mild, but yesterday's temperature was hot and the air conditioner was on, it is likely that the air conditioner will also be used today. Similarly, if yesterday's temperature was mild and air conditioning was not used, then if today's temperature

[71] Menne, M.J., and C.N. Williams, Jr., (2009) "Homogenization of temperature series via pairwise comparisons." *J. Climate*, **22**, 1700-1717.

[72] To calculate the Dth day's two-day weighted mean temperature ($TWMT_D$), the current day's (D) daily mean temperature (DMT_D) is averaged with the prior day's (D-1) daily mean temperature (DMT_{D-1}), applying a 2/3 weight on the current day and 1/3 weight on the prior day: $TWMT_D = (2/3)\ DMT_D + (1/3)\ DMT_{D-1}$.

is slightly warmer, air conditioning may not be used until later in the day. Staff used the MCI daily two-day weighted mean temperature data series to normalize both class usages and hourly net system loads.

Calculation of Normal Weather - Staff used a ranking method to calculate normal weather estimates of daily normal temperature values, ranging from the temperature that is "normally" the hottest to the temperature that is "normally" the coldest, thus estimating "normal extremes." Staff ranked the two-day weighted temperatures for each year of the 30-year history from hottest to coldest and then calculated the normal daily temperature values by averaging the ranked two-day weighted mean temperatures for each rank, irrespective of the calendar date.

This results in the normal extreme being the average of the most extreme temperatures in each year of the 30-year normals period. The second most extreme temperature is based on the average of the second most extreme day of each year, and so forth. Staff's calculation of daily normal temperatures is not the same as NOAA's calculation of smoothed daily normal temperatures. Because the test year temperatures do not follow smooth patterns from day to day, Staff calculated normal daily temperatures based on the rankings of the actual temperatures of the test year period. Staff's calculation procedure of weather variables in MCI has been used past rate cases including the last GMO rate case ER-2012-0175.

Staff Expert/Witness: Seoung Joun Won PhD

b. Weather Normalization

In many of the classes of service, electricity consumption is highly responsive to the weather, specifically temperature. As the temperature increases, the demand for cooling, air conditioning and fans increases the customers' consumption of electricity. As the weather becomes cold and the temperature falls, the demand for additional heating, for example electric space heating, also forces an increase in electricity consumption. Because electric air conditioning and space heating is prevalent in GMO's service territory, GMO's electric load is linked and responsive to daily changes in temperature.

Staff used the most recent temperature and load data available for the test year period of July 1, 2014, through June 30, 2015, to capture a more likely, forward-looking indictor of non-weather electricity usage per customer. November 2014 and February 2015 experienced temperatures colder than normal, and June 2015 experienced temperatures hotter than normal, resulting in electric energy usage above that which would have been expected under normal weather conditions. December 2014 and January 2015 experienced temperatures more mild than normal resulting in usage below that which would have been anticipated under normal conditions. The temperatures used by Staff in the test year period deviated from normal, thus Staff performed a weather impact analysis using loss factors reviewed by Staff witness Alan J. Bax.

Staff's model and methodology contained elements important in the class level weather normalization process; in particular, use of daily load research data to determine non-linear, class and district specific responses to changes in temperature with the incorporation of different base usage parameters to account for different days of the week, months of the year, and holidays. The results of Staff's analysis were provided to Staff witnesses Robin Kliethermes and Seoung Joun Won to be used in the normalization of revenues for each district's weather sensitive classes: Residential ("RES"), Small General Service ("SGS"), Large General Service ("LGS") and Large Power Service ("LPS") classes.

Staff Expert/Witness: Seoung Joun Won, PhD

c. 365-Days Adjustment to Usage

Calendar months and revenue months differ from one another because the periods they cover begin and end at different times. Calendar months coincide with the calendar, beginning on the first day of the month and ending on the last day of the month.

For weather sensitive classes, except Large Power Service ("LPS"), revenue months are an aggregation of bill cycles and begin on the first day of the first billing cycle and end on the last day of the last billing cycle. This aggregation of bill cycles may or may not coincide with a 365-day calendar year. In order to account for this difference, a "365-days adjustment factor" is calculated to convert the annual weather normalized revenue month usage to associate with the annual weather normalized calendar month usage. The adjustment factors were made to the test year months in proportion to the actual usage occurring in each month and then appropriate rates were applied to determine the revenue adjustment of Staff witness Robin Kliethermes.

For 365-adjustments of LPS customers, please see the large customer sections of Staff witness Seoung Joun Won.

Staff Expert/Witness: Seoung Joun Won, PhD

4. Regulatory Adjustments to Test Year Sales and Rate Revenue

a. Normalization and Annualization of GMO Billing Determinants

Staff normalized and annualized billing determinants for the RES, SGS and LGS rate classes based on the normalized and annualized kWh factor supplied by Staff witness Seoung Joun Won.[73] For example, if the normalized and annualized kWh factor is 0.97 for the month of September in the RES rate class, then the total actual usage for that month and for that rate class is decreased by 3%.

Staff adjusted the total of the actual blocked billing determinants to equal the normalized and annualized monthly kWh using the relationship between actual average usage per customer and normalized and annualized average usage per customer. Staff also used the relationship between percentage of usage priced in the first rate block and the second rate block to distribute normalized and annualized monthly kWh to the rate blocks for rate classes RES, SGS and LGS. This calculation resulted in normalized usage by rate block, which were then converted to total normalized and annualized revenues by multiplying rate block usage by the appropriate rates.

The overall difference between GMO's actual billing determinants and rate revenue and Staff's normalized and annualized billing determinants and rate revenue results in Staff's normalized and annualized kWh and revenue adjustment.

Staff Expert/Witness: Robin Kliethermes

5. Customer Growth

a. Customer Growth in kWh Sales

Staff calculated the customer growth kWh sales to reflect the additions and, in certain instances, reductions to kWh sales that would have occurred if the number of customers taking service at the end of the update period (December 31, 2015) had existed throughout the entire test year. I provided Staff witness Robin Kliethermes the growth in kWh sales for the following rate classes:

> For MPS, the MO815, MO860, MO865, MO866, and MO870 Residential rate classes; the MO710, MO711, MO728, MO716,

[73] Separate adjustments are calculated for the change in kWh due to weather normalization and the change in kWh due to the annualization of the number of days in the test year. The combined impact of these adjustments are applied to kWh as a single adjustment factor for ease of application.

> MO867, and MO868 Small General Service rate classes; and the MO720, MO725, and MO722 Large General Service rate classes.
>
> For L&P, the MO910, MO915, MO920, MO922, MO965, and MO966 Residential rate classes; the MO928, MO930, MO931, MO941, MO967, and MO968 Small General Service rate classes; and the MO938, MO939, MO940, and MO942 Large General Service rate classes.

Ms. Robin Kliethermes addresses the impact of the customer growth adjustment to rate revenue in the following section of this Report.

Staff Expert/Witness: Ashley Sarver

b. Customer Growth in Rate Revenue

Staff adjusted usage and revenue through December 31, 2015, for the MPS and L&P rate districts for customer growth to reflect the additional usage and rate revenues that would have occurred if the number of customers taking service at the end of December 31, 2015, had existed throughout the entire test year using the kWh information provided by Staff witness Ashley Sarver.

As noted above, Staff is recommending that one set of rate schedules be developed for all GMO's customers rather than district specific rate schedules. However, as it is also noted above, since there are currently different rate schedules for rate classes in the L&P and MPS rate districts, Staff had to normalize and annualize these customer classes separately. Staff added the results of the final adjustments for GMO's MPS and L&P rate districts together for GMO company-wide rate revenue and usage.

Staff Expert/Witness: Robin Kliethermes

6. Customer Discounts

EDR: The Economic Development Rider ("EDR") provides for discounts to be "paid" to large customers (in the form of credits on their electricity bill) who locate or expand operations in GMO's service territory including both MPS and L&P customers.[74] EDR credits are provided to the customer over a five-year period. The value of the credits is a percentage of the customer's electric bill calculated on the appropriate general application rate schedule.

[74] Both rate districts are served by the same EDR rider.

Depending upon which contract year the customer is in, the discount can be as high as 30% to as low as 5%. These discounts are included in the determination of GMO revenues.

Staff Experts/Witnesses: Robin Kliethermes

B. Large Power Service ("LPS") Adjustments

Large Power Service ("LPS") rate class - The adjustments to billing units and revenues were based upon the test year of July 1, 2014, through June 30, 2015, to be adjusted for known and measurable changes through the update period December 31, 2015. There were about 260 customers in the LPS rate class during the test year. A data check was performed for each customer monthly billing correction prior to doing other adjustments. LPS customers were normalized and annualized on an individual customer billing account basis.

The details of LPS energy usage and revenue adjustments are as follows:

(a) Weather Normalization

Staff normalized the actual usage data from the test year data provided by GMO for each LPS customer by applying monthly weather normalization factors for each rate district (MPS and L&P) provided by Staff witness Seoung Joun Won. Staff adjusted the billing units associated energy by these factors for each month, and applied current rates to determine the weather-normalized revenue. The difference between these weather-normalized revenues and the test year actual revenues determined the amount of the weather normalization adjustment.

(b) Annualization

The general intent of an annualization is to restate the results of the test year billing units as if conditions known at the end of the test year had existed throughout the entire test year. Staff reviews each of the very largest customers to determine if adjustments need to be made to reflect any major growth or decline in kWh usage and rate revenues due to the entrance of new customers, the exit of existing customers, and load growth or decline of specific existing customers. These customers' billing units and revenues were annualized for all twelve (12) months.

During the test year and through the update period, there were thirty (30) customer changes: eight (8) customers in MPS were terminated accounts and eight (8) customers in MPS and two (2) customers in L&P were new, three (3) customers in MPS and one (1) customer in

L&P switched rate classes from LGS to LPS, and eight (8) customers in MPS switched rates from LPS to LGS. These customer changes were annualized, in order for every customer in the LPS class to have 12-months of usage and revenue. Exited LPS customers' usages were removed and new LPS customers' 12-months usages were applied that was representative of their existing usage.

As part of load annualization, each LPS customer's current and historical usage was analyzed on an individual basis to find changes in load growth or decline. As a result of that analysis, eleven (11) LPS customers' loads were adjusted. Loads that seemed inconsistent or expected a change in the future were replaced by average numbers from adjacent months or by monthly data from other years when the load seemed a better representation of future consumption. Their individual monthly demand and energy use, measured over multiple years prior to the test year and the twelve months of the test year, were examined graphically to determine if an adjustment was needed to reflect an annualized/normalized level of demand and energy use for the 12-month test year, as well as to identify the type of adjustment required to reflect the appropriate annualized/normalized level.

(c) 365-Days Adjustment

Rate revenues and billing units were measured by billing month (the period of time over which the staggered bill cycles result in each customer being billed precisely once) rather than by calendar month. The number of days in the twelve (12) billing months comprising the test year for each customer was compared to a 365-day calendar year. For those LPS customers with the billing cycles of the test year totaling greater or less than 365 days, a per-day kWh adjustment was made, with the appropriate rates applied to determine the revenue adjustment. After the normalization was calculated, the 365-days adjustment for the test year was calculated. Appropriate rates were applied to each month's adjusted usage to obtain revenue. The differences between the revenues produced by the 365 days adjusted usage and the actual usage are the "365-days" revenue adjustments.

Staff Expert/Witness: Seoung Joun Won, PhD

C. Rate Structure-Related Revenue Adjustment

The rate structure GMO has proposed for total companywide rates is not identical to the rate structures that currently exist for either GMO's MPS rate district or GMO's L&P rate district. For example, the minimum demand that is billed regardless of actual usage for an LGS customer on the total-company rate structure is 150kW, while it is currently 40kW for a customer served on the L&P LGS rate schedule, and 100kW for a customer served on the MPS rate schedule.[75] As will be discussed in greater detail in Staff's Report on Class Cost of Service and Rate Design, it is expected that many customers will change the nominal class under which they receive service. To the best of its ability, Staff is reviewing the likely "best fit" of customers under the proposed rate structure. To account for changes in the revenue produced by GMO's customers as those customers are moved to the most appropriate rate schedule, it is likely that Staff will recommend an adjustment to Rate Revenues to reflect the difference between the revenue that would be produced from the billing determinants of each class as currently constituted versus the billing determinants for each class that would be applicable to total-company rates.

Staff Experts/Witnesses: Robin Kliethermes

D. Results

Normalized and annualized kWh usage was used to develop the total Net System Input ("NSI"). Rate revenue, for both GMO's MPS and L&P rate districts, with adjustments, are at the Rate Revenue Summary Tab of Staff's Accounting Schedules.

Staff Experts/Witnesses: Robin Kliethermes

E. Transmission Revenue-FERC Account 456

GMO books transmission revenue to FERC Account 456. GMO receives revenues from SPP on the following SPP tariff schedules:

- Schedule 1: System Control and Dispatch Service
- Schedule 2: Revenues related to reactive supply for generators connected to the transmission system

[75] While the names of classes GMO has proposed for total-company rates are identical to the names of classes that currently exist in each rate district, the rate structures and customer characteristics are significantly different.

- Schedule 7: Revenues related to firm point to point transmission
- Schedule 8: Revenues related to non-firm point to point transmission
- Schedule 9: Revenue related to network integrated transmission
- Schedule 11: Revenues related to the base plan transmission upgrades
- Other miscellaneous transmission revenue

Although GMO receives revenues from SPP based on all of the schedules listed above, a significant percentage of the transmission revenues received from SPP are from network integrated transmission, firm point-to-point transmission and base plan transmission activities.

Staff analyzed GMO's transmission revenue for the period of 2009 through 2015, and reviewed GMO's proposed wholesale revenue adjustment. The wholesale revenue adjustment proposed by GMO is the difference in GMO's authorized FERC ROE of 11.1% and GMO's proposed ROE in this case of 9.9% and is discussed in further detail below.

The following chart reflects GMO[76] and its MPS and L&P rate districts' historical transmission revenues for the period of 2009-2015:

Year	GMO Transmission Revenue
2009	** $______ **
2010	** ______ **
2011	** ______ **
2012	** ______ **
2013	** ______ **
2014	** ______ **
2015	** ______ **

Staff identified an upward trend in GMO's transmission revenue; therefore, Staff recommends an annualized level of GMO's transmission revenue based on the 12 months ending December 31, 2015. Staff's adjustment is identified on Schedule 9 of Staff's GMO Consolidated, MPS and

[76] GMO transmission revenue is the sum of transmission revenue for MPS and L&P rate districts.

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L&P Accounting Schedules, Adjustment Rev-25.1. Staff will review this adjustment during the True-Up audit in this case.

As mentioned above, in its direct case, GMO proposed an adjustment to reduce transmission revenue for the difference in GMO's authorized FERC ROE of 11.1% and GMO's proposed ROE in this case of 9.9%. As a transmission owner, GMO receives transmission revenues from SPP for regional and zonal transmission upgrades. The wholesale transmission revenue adjustment is calculated using the Annual Transmission Revenue Requirement ("ATRR") and using GMO's authorized FERC ROE of 11.1%. The ATTR is used by SPP to allocate revenues and expenses to all transmission owners and transmission customers of SPP. The transmission owners receive allocated revenues based on the ATTR and the transmission customers are charged for allocated costs based on the ATTR. The ATTR may include incentives such as allowing CWIP in the revenue requirement, ROE adders, etc. GMO's authorized FERC ROE of 11.1% includes a ROE adder for being a member of a regional transmission organization ("RTO") of 50 basis points.

Other SPP transmission owners submit the ATTR that may include the previously discussed incentives. GMO will then receive its allocated share of the transmission costs that include these incentives. Since no adjustment was made to its transmission expense for the incentives that are included in the costs GMO receives from SPP and charges to its customers, Staff did not reduce transmission revenues for the difference in GMO's authorized FERC ROE of 11.1% and its proposed ROE of 9.9% in this case.

Staff Expert/Witness: Karen Lyons

F. Ancillary Services

Ancillary services, also known as operating reserves, include Regulation-up, Regulation-down, Spinning Reserve, and Supplemental Reserve services. These services support the transmission of capacity and energy while maintaining the reliability of the transmission system. Regulation–up and Regulation-down maintains the balance between the generation and the load. Spinning and Supplemental reserve requires that an energy resource such as a power plant must be available in the event of an outage. Prior to March 1, 2014, GMO was part of an Energy Imbalance Service market ("EIS") and self-designated ancillary services. On March 1, 2014, the SPP Integrated Marketplace began replacing the previous EIS market.

Consequently, GMO now purchases ancillary services for its load from SPP and sells ancillary services to SPP.

Staff annualized ancillary services for the 12-month period ending December 31, 2015, the update period in this case and is included in Staff's Off-System Sales adjustments.

Staff Expert/Witness: Karen Lyons

G. Revenue Neutral Uplift

The revenue neutral uplift charges are imbalances between revenues and disbursements that are distributed by SPP to SPP market participants as either a charge or a credit. As a not-for-profit organization, SPP must remain revenue neutral. Consequently, SPP will charge or credit GMO for the revenue neutral uplift charge. The charge consists of miscellaneous charges or credits that SPP has no other method of distributing to SPP market participants.

Staff annualized revenue neutral uplift charges for the 12-month period ending December 31, 2015, the update period in this case and is included in Staff's Off-system Sales adjustments.

Staff Expert/Witness: Karen Lyons

H. Off-System Sales

1. <u>FERC Account 447-Sales for Resale</u>

FERC Account 447, Sales for Resale, includes three sources of revenue for GMO:

- firm off-system sales;
- non-firm off-system sales; and
- FERC wholesale sales

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

During the Test Year ended June 30, 2015, updated through December 31, 2015, GMO's MPS rate district contracted to sell firm off-system power to Black Hills Power, Inc. ("Black Hills"). GMO's L&P rate district currently does not have firm off-system sales contracts. On a company-wide basis, the revenues received from Black Hills will be included in

GMO's consolidated cost of service. Black Hills pays a demand charge for the megawatt capacity commitment from MPS and an energy charge for the cost of delivered energy. As a result, Staff annualized MPS's firm demand and energy sales based solely on the capacity contract in effect with Black Hills as of the update period ended December 31, 2015.

Staff has reviewed MPS's firm off-system sales levels and adjusted test year levels to reflect the levels for the 12-month update period ended December 31, 2015.

3. Border Customers

Border customers are customers who are in the service territory of one utility to which the customer will pay its bill, but are physically served by another utility's power lines. In other words, there are GMO customers currently being served by another utility's power and customers of other utilities that are being served by GMO's power. When GMO customers are served by another utility, GMO must pay the utility for the costs to serve GMO's customers. The energy supplied by another utility for GMO's customers is included in Staff's fuel model as a reduction to the net system input ("NSI") and the revenues for GMO customers that are served by another utility are included in Staff's retail revenue and included in GMO's cost of service. When another utility's customers are served by GMO, the utility must reimburse GMO for the cost of serving those customers. The energy supplied by GMO is included in Staff's fuel model and the related fuel costs are included in GMO's cost of service.

To ensure that all border customer costs and revenues are included in GMO's cost of service, an additional adjustment must be made to include the payment GMO makes to reimburse other utilities for the costs to serve GMO's customers – purchased power, and the payment GMO receives from other utilities for the costs to serve those utilities' customers -- sales.

Staff analyzed and combined MPS and L&P border customers' purchased power and sales for the cut-off period, twelve months ending December 31, 2015.

4. Non-Firm Off-System Sales

For purposes of discussing revenue requirement calculations, non-firm off-system sales are sales of electricity made at times when a utility's generation output exceeds the load requirements of its native load customers (rate tariff customers) and firm sale customers. GMO must first meet its firm sales loads and, if it has excess electricity to sell, it will make off-system sales. The difference between the revenue received for selling the excess generation and the cost of the fuel used to produce the energy sold are referred to as off-system sales margin ("OSSM"). Off-system sales are made at market-based rates. Off-system sales are made through GMO's generation or through electricity purchased from other utilities. The aggregate off-system sales net margins are used in the revenue requirement calculation.

Since March 2014, GMO has taken part in the SPP integrated market. GMO offers its generating units for dispatch through the SPP, and the SPP dispatches GMO and all other SPP generating owners' generation to meet the load requirements of the entire SPP region. For purposes of discussing revenue requirement calculations, once all firm commitments are met (native load), any excess generation is available to sell through the market on a non-firm basis—off-system sales.

5. FERC Wholesale Sales

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

6. Removal of Inter-Company/Rate District Energy Transfers

This adjustment eliminates inter-company energy transfers between the MPS and L&P rate districts that were recorded during the test year. The revenues and expenses associated with the eliminated energy transfers for both MPS and L&P rate districts are the actual per book amounts for the test year ended June 30, 2015. All of Staff's Off-system sales adjustments are identified on Schedule 9 of Staff's GMO Consolidated, MPS and L&P Accounting Schedules, Adjustments Rev-7.1, Rev-9.1, Rev.-9.2, Rev.-11.2, Rev.-13.1, and Rev-14.1

Staff Expert/Witness: Karen Lyons

I. SO^2 Emissions Allowances

1. <u>Deferred Sales from SO^2 Emissions Allowances</u>

GMO receives SO2 emission allowances ("SO2 allowances") from the United States Environmental Protection Agency ("EPA"), each of which authorizes GMO to emit 1 ton of emissions during a given compliance period. GMO uses these allowances to serve its electric customers. Because GMO has reduced its emissions below the number of allowances it holds, the EPA also holds back of the additional unused allowances for the specific purpose of having allowances available for auction. When the allowances are sold at the annual EPA auction, the proceeds are forwarded to GMO. Under the FERC Uniform System of Accounts ("USOA"), proceeds from the sales of SO2 emissions allowances are recorded in FERC Account 254, the regulatory liabilities account. For ratemaking purposes, amounts recorded as regulatory liabilities reduce a utility's rate base, i.e., the net amount in FERC Account 254, after any appropriate adjustments, is an offset to rate base. However, GMO did not have any sales of emission allowances in the test year so no allowances were available as an offset to rate base.

When emission allowances are purchased they are accounted for in FERC Account 158. Staff examined GMO's work papers where a 13-month average was used to determine a level of emission allowances added to rate base. Staff has included in its direct case the balance of Account 158.100 on December 31, 2015, as an addition to rate base. This approach is consistent with the treatment in the last four GMO/Aquila rate cases, Case Nos. ER-2007-0004, ER-2009-0090, ER-2010-0356 and ER-2012-0175. The rationale for treating these SO2 emissions allowances in this manner is to acknowledge that, through rates, GMO's customers either have paid for GMO's production facilities that reduce emissions and thus create these overages in SO2 emissions allowances or had to give recognition for the purchase of emission allowances which had to be included rate base. In this instance, the emission allowances were included in Accounting Schedule 2-Rate Base for the GMO Consolidated case. Also, Adjustment E-21.1 made to the Accounting Schedule 9 - Income Statement removes the test year level of emission allowances. This same adjustment is made to both the MPS and L&P revenue requirement runs as E-21.1.

Staff Expert/Witness: Cary G. Featherstone

J. Miscellaneous Revenues

1. Late Payment Revenue (Forfeited Discount)

GMO charges a late payment fee to customers who fail to pay bills in a timely manner. Staff annualized late payment fee revenues by using the ratio of late payment fees to Missouri total retail sales from January 31, 2015, through December 31, 2015. This ratio was multiplied by the Staff annualized revenue resulting in an annualized level of late payment fees. Staff's adjustments are identified on Schedule 9 of Staff's GMO consolidated, MPS and L&P Accounting Schedules, Adjustments Rev-16.1 and Rev-17.1, respectively.

Staff Expert/Witness: Keith Majors

K. Other Revenue Accounts

Staff summed the amounts of "Other Revenues" for GMO's L&P and MPS rate districts in order to develop an amount of GMO consolidated revenues. "Other Revenues" include reconnect and tampering charges, meter damage charges, collection fees, excess facilities charges, sales and use tax timely filing discounts, and return check service charges.

Staff examined the most recent five-year (January 2011 – December 2015) history of GMO's "Other Revenues." Staff concluded the test year amounts for "Other Revenues" appeared to be reasonable and representative of an annualized level of revenue for each respective category and, therefore, do not require adjustment. Staff will examine these revenue accounts again during its true-up audit, in which it will review data through July 31, 2016.

Staff Expert/Witness: Ashley Sarver

VIII. Income Statement – Expenses

A. Fuel and Purchased Power Overview

GMO has 2086 megawatts of total generating capacity, consisting of coal-fired, natural gas, and oil-fired generating units. Based on calendar year 2015 operating results, GMO's generation capacity is made up of the following types of generation:

Generation Capacity by Fuel Type	2015 Megawatts	Percentage of Generation Capacity by Fuel Type	2015 Percentage of MWHs Generated by Fuel Type
Coal	920 MWs	44.10%	95.17%
Natural Gas/Coal	115 MWs	5.51%	
Natural Gas	666 MWs	31.93%	3.14%
Natural Gas/Oil	325 MWs	15.58%	
Oil	60 MWs	2.88%	.13%
Tire-Derived Fuel, Propane, Biofuel (Note)			1.56%
Total	2086 MWs	100%	100%

Source: 2015 Annual Report- pages 8 and 22.

Note: GMO also uses alternative fuel sources that include Tire-Derived Fuel, Propane and Biofuel. These fuel sources are not listed in GMO's 2015 Annual Report. Combined, they account for less than 2% of the MWhs generated.

While GMO's coal-fired generating units make up 44% of its total generating fleet, those units produce 95% of total system load requirements. Natural gas generating capacity makes up 53% of total GMO capacity, but it produces 3% of total generation. Oil capacity makes up 3% of total capacity, but this fuel type makes up less than 1% of GMO's total generation, based on 2015 actual megawatt hours of generation. Based on the actual 2015 generation by fuel type, coal and natural gas make up 98% of total generation with oil, propane, tire-derived fuel and biofuel making up less than 2% of GMO's generation. The graph below shows 2012-2015 actual generation based on MMBTU's:

continued on next page

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Staff Expert/Witness: Karen Lyons

B. Fuel and Purchased Power Expense

Staff estimates GMO's variable fuel and purchased power expense to be $163,807,507 for the twelve month test year ending June 30, 2015. Staff is currently engaged in dialog with GMO regarding differences with generation dispatch and will continue to work to understand the differences in generating unit behavior within the market.

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Staff uses the PLEXOS production cost model to perform an hour-by-hour chronological simulation of a utility's generation and power purchases. Staff uses this model to determine annual variable cost of fuel, net purchased power costs, and fuel consumption. These amounts are supplied to Auditing Department Staff who use this input in the annualization of fuel expense. PLEXOS was also used to provide inputs for the calculation of allocation factors between the MPS and L&P rate districts[77].

Staff used market prices in its fuel model dispatch to simulate GMO's operations in the Southwest Power Pool's ("SPP") Integrated Marketplace. The price for energy in the Integrated Marketplace dictates the amount of energy GMO sells.

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

Staff calculated the following inputs for use in the model: fuel prices, firm purchased power contract specifications, hourly net system input, and unit planned and forced outages. Staff relied on GMO's responses to data requests and data GMO supplied to comply with 4 CSR 240-3.190 for the characteristics of each generating unit; for example: capacity of the unit, unit heat rate, primary fuel type, ramp-up rate, startup costs, and fixed operating and maintenance expense. Information from GMO's firm wholesale loads and firm purchased power contracts such as hourly energy available and prices are also inputs to the model.

Staff Expert/Witness: Charles T. Poston, PE

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

Planned and forced outages are infrequent in occurrence and variable in duration. In particular, forced outages are unplanned and can happen at any time. In order to capture this variability, average yearly planned outage durations and forced outage rates were calculated for GMO generating units. The average values for each generating unit were based on seven years

[77] In order to develop separate levels of fuel and purchased power expense for GMO's MPS and L&P standalone accounting schedules, Staff developed allocation factors to assign the appropriate level of fuel and purchased power expense between the MPS and L&P rate districts.

of data when available. The outage information was taken from responses to Staff data requests and from information supplied by GMO to comply with 4 CSR 240-3.190.

Staff Expert/Witness: Charles T. Poston

2. <u>Heat Rate Testing Review</u>

If an electric utility requests that a Rate Adjustment Mechanism (Fuel Adjustment Clause ("FAC")) be continued or modified, Commission Rule 4 CSR 240-3.161(3)(Q) requires that an electric utility shall file specific information as a part of its direct testimony in a general rate proceeding:

> (Q) The results of heat rate tests and/or efficiency tests on all the electric utility's nuclear and non-nuclear steam generators, HRSG, steam turbines and combustion turbines conducted within the previous twenty-four (24) months;

The Commission authorized GMO's FAC in Case No. ER-2007-0004.[78] The FAC was continued in Case Nos. ER-2009-0090, ER-2010-0356, and ER-2012-0175. GMO has again requested the FAC be continued in the current general rate proceeding, Case No. ER- 2016-0156.

GMO witness Burton L. Crawford filed the results of the most recent heat rate/efficiency tests for GMO's generating units in schedule BLC-6 of his direct testimony. Staff has conducted a review of those results and found them to be reasonable based on comparisons with data filed in previous general rate case proceedings. All of the testing dates submitted by GMO were found to be in accordance with the twenty-four (24) month requirement of 4 CSR 240-3.161(3)(Q).

Staff Expert/Witness: Charles T. Poston

3. <u>Lake Road Electric/Steam Allocation Factors</u>

The Lake Road Plant is made up of seven boilers, four steam turbine generators, and three combustion turbines. The steam turbine generators at Lake Road are divided between two steam systems based upon their operating pressures. Lake Road Unit 4/6 operates at a nominal pressure of 1800 lbs. and is supplied steam by a single boiler. Units 1, 2, and 3 are commonly referred to as being a part of the 900 lb. steam system. The 900 lb. steam system is itself divided

[78] The FAC was initially granted to Aquila, Inc.

between 900 lb. and 200 lb. steam headers. Units 1 and 2 are connected to the 900 lb. steam header that is supplied steam by four boilers. The 900 lb. steam header is connected to a 200 lb. steam header that is supplied steam by two additional boilers along with the steam discharged from the Unit 1 turbine. Lake Road Unit 3 is supplied steam from the 200 lb. steam header. Both steam headers also supply steam to industrial steam customers. The interconnection of boilers and steam turbines on the 900 lb. steam system allows for operational flexibility when generating steam either for sale to industrial steam customers or for producing electricity for sale in the market. As a result of this configuration, plant costs must be allocated between the two different types of customers. A method to accomplish this is already in place, but recent changes at Lake Road Unit 4/6 require a reevaluation of the allocation factors.

During the spring of 2016, the primary fuel source for Unit 4/6 was switched from coal to natural gas. Lake Road Units 1, 2, and 3 will not be directly affected by this change as they will continue to be supplied with steam from lower pressure boilers that are fed either by coal, natural gas, or fuel oil. Staff found that electrical generation and industrial steam sales on the 900 lb. steam system have not significantly changed in the past five years. However, with the new operating characteristics of Unit 4/6 yet to be determined, it is unclear how it will be dispatched within the market and if there is a potential to indirectly impact electrical generation at Lake Road Units 1, 2, and 3. Any changes to the use of steam on the 900 lb. system will influence the allocation of costs between electric and steam customers. In its review of historic trends in the Lake Road electric/steam allocation factors, Staff determined that over the past decade allocations have been generally shifting away from electric customers and toward industrial steam customers. At this time, there is no evidence that suggests that this trend will change.

Therefore, Staff recommends that the Lake Road electric/steam allocation factors remain at the values submitted in Schedule JPW-6 (SJLP) of the direct testimony of John P. Weisensee in Case No. ER-2012-0175. Any changes to the values of the allocation factors or their methods of calculation should be deferred to future electric and steam rate cases to allow for the effects of the operational changes at the Lake Road Plant to be more fully understood and documented. Staff also recommends that GMO perform a study to reanalyze all of the electric/steam allocation factors in a manner similar to that done to create the allocation procedures in Case No. EO-94-36. This study should be completed prior to the submission of any future changes in the methods used to calculate electric/steam allocation factors. With the uncertainty surrounding the potential impacts from the changes at Lake Road 4/6 and no evidence of any other significant changes in the use of the 900 lb. steam system, it is not appropriate to make changes to the Lake Road electric/steam allocation factors at this time.

Staff Expert/Witness: Charles T. Poston

4. Fixed Costs

Fuel and purchased power costs that do not vary directly with the amount of fuel burned were not included in Staff's fuel model, but were determined separately. The non-variable fuel costs that were determined separately and included in fuel expense are typically referred to as "fuel adders." These types of costs include non-wage fuel handling, dust suppressant, and freeze proofing coal for transportation from the mines to power plants. In addition, the non-variable purchased power costs not included in Staff's fuel model are commonly referred to as "capacity charges" or "demand charges" and are annualized separately from purchased power energy costs, and will be addressed later.

Staff Expert/Witness: Karen Lyons

5. Fixed Adders

As described above, fuel adders do not vary directly with the amount of electricity produced, so these costs are not included in Staff's fuel model. The cost of fuel adders are determined separately and are added to the level of fuel expense determined by the model, which gives the overall fuel expense level Costs added to coal expense include unit train lease payments and unit train rail car maintenance costs. Fuel adders for natural gas include transportation charges and hedging costs. A significant percentage of natural gas transportation charges is fixed and under contract. Other fuel adders include ammonia, urea, limestone, and powder activated carbon ("PAC").

For natural gas fixed transportation costs and additives such as limestone and ammonia, Staff used the actual expenses for the 12-months ending December 31, 2015. Staff's adjustments are identified on Schedule 9 of Staff's GMO consolidated Accounting Schedules, MPS and L&P Accounting Schedules, Adjustments E-9.1 and E-10.1. The Hedging costs are addressed in the FAC portion of this report. Staff will re-examine these expenses at the time of Staff's true-up, and update any costs as necessary.

Staff Expert/Witness: Karen Lyons

6. <u>Purchased Power – Energy</u>

Staff Adjustments E-65.1, E-66.1 and E-67.1 annualizes purchased power energy charges based on Staff's fuel model results. These purchased power energy charges represent the energy GMO purchases on the spot market and through contracts to meet the system load requirements of its retail electric customers. Staff witness Erin L. Maloney is responsible for determining the appropriate amount of purchased power and the proper price for this power, and provided the results to Staff witness Charles T. Poston, who was responsible for operating the fuel model and for providing various inputs to this model.

Staff Expert/Witness: Karen Lyons

7. <u>Purchased Power – Capacity Charges</u>

Capacity charges, commonly referred to as "demand charges," represent fixed amounts that GMO pays for the "right" to purchase power or is paid by another entity for the "right" to purchase power from GMO. In the case of purchased power, the selling entity reserves generating capacity for GMO to purchase when the electricity is needed under terms of the purchased power agreements. GMO contracts for this power with various entities and pays a fixed component for the reserve capacity and an energy component for any energy consumed. Generally, there is also an amount for operational and maintenance costs charged for the usage of energy. The fixed component is paid by GMO as a demand charge, generally on a monthly basis, regardless of the level of power actually purchased. This amount is for the "right" to purchase the power in much the same way that natural gas utilities purchase the reservation of capacity from pipelines through reservation payments. The demand charges relate to the fixed expenses of operating a generating facility.

The demand charges paid to GMO by other generating entities, giving those entities the "right" to purchased power from GMO, are known as capacity sales. The demand charges for capacity sales are addressed in the revenue portion of this Cost of Service Report Staff's adjustments to annualize purchased power demand charges based on existing capacity contracts currently in effect are identified on Schedule 9 of Staff's GMO Consolidated, MPS and L&P Accounting Schedules, Adjustment E-68.1. These charges represent amounts that are paid under capacity agreements related to the fixed costs of reserving capacity. Staff determined the appropriate costs per megawatt hour and the amount of megawatts purchased for each contract. Staff included the costs reflected in GMO's capacity agreements that were in effect on December 31, 2015.

Staff Expert/Witness: Karen Lyons

8. <u>Variable Costs</u>

a. Fuel Prices

Staff computed coal fuel expense using coal prices and quantities as of January 1, 2016. For all other fuel expenses, Staff computed fuel expense using prices and quantities actually incurred by GMO as of December 31, 2015. Staff included fuel prices for coal, natural gas, and oil, including transportation charges in fuel accounts 501 (coal), 547 (natural gas) and 555 (energy portion of purchased power expense).

Staff Expert/Witness: Karen Lyons

b. Coal Prices

Staff determined coal prices by generation facility based on a review and analysis of GMO's coal purchase (supply) and coal transportation (freight) contracts. Staff's recommended coal prices reflect GMO's actual contracted coal purchase and transportation prices (excluding sulfur premiums or discounts) in effect on January 1, 2016. Staff will review the coal prices during the audit process of the true-up.

Staff Expert/Witness: Karen Lyons

c. Natural Gas Prices

As an input to its production cost model, Staff used twelve (12) monthly natural gas prices calculated using 12-month weighted averages of GMO's actual commodity cost of natural gas through the end of the known and measurable period of December 31, 2015. GMO's natural gas fixed transportation costs are annualized and normalized separately as a part of fuel adders.

Staff Expert/Witness: Karen Lyons

d. Oil Prices

Staff used the actual cost GMO paid for its most recent fuel oil purchases to determine variable fuel oil expense. GMO burns fuel oil mainly as a start-up fuel for the coal-fired generating units, or in some instances for flame stabilization. As a result, GMO purchases fuel oil infrequently. Historically, the limited number of purchases of fuel oil makes it difficult to employ any meaningful type of averaging method. An accurate historical analysis of fuel oil prices is also not possible because GMO does not make purchases during the majority of the year. For its direct filed case, GMO purchased oil in 2015 and therefore Staff recommends used GMO's most recent fuel oil purchase prices as of December 31, 2015, to input into the fuel model for determining GMO's variable fuel and purchased power expense on a going forward basis.

Staff Expert/Witness: Karen Lyons

9. Purchased Power Prices

Staff analyzed hourly SPP Integrated Market Day Ahead ("SPP-IM DA") power prices beginning with the start of the market on March 11, 2014, through the end of June 2016. Staff calculated the monthly average peak and off-peak prices for each month in this period from the actual SPP-IM data using the average hourly GMO purchase node prices.

Actual pricing data for the SPP-IM DA market is limited to the last nine months of 2014 and the first 6 months of 2016. While the market prices stabilized since the extreme highs of early market operation in 2014, the market prices in early 2016 appear to have taken a down turn. An analysis of the two-year (or three-year when available) average prices shows a close correlation between the average SPP prices and the market prices presented in the Company's direct filing. This can be seen in the charts and graphs contained in Appendix 3, Schedule ELM-d1.

As described on page two in Company witness Burton Crawford's direct testimony, the Company used the MIDASTM model to forecast purchased power prices. This model used public available data to generate a set of 8,760 hourly prices to be used as input to the Company's fuel model.

Since the onset of the two-day markets in Missouri, Staff has used a three-year peak and off-peak average of market prices (when data is available) to eliminate extreme price points caused by anything from weather, new market operation, hurricanes, economic down turns, and flooding. For Staff's direct case, the Company's market prices have been adopted as a reasonable normalized forecast of market prices.

Staff will continue to review purchased power prices through the true-up period and will update prices as necessary.

Staff Expert/Witness: Erin L. Maloney, PE

10. Normalized Net System Input

Hourly net system input is the hourly electric supply necessary to meet the hourly energy demands of the utility's customers and is net of (i.e., does not include) station use, which is the electricity requirement of the utility's generating plants.

Due to the presence of significant air conditioning and electric space heating in GMO's service territory, the magnitude and shape of GMO's net system input is directly related to daily temperatures. To normalize net system input, Staff used actual and normal daily temperatures provided by Staff witness Dr. Seoung Joun Won in its analysis. The actual daily temperatures for the test year, twelve months ending July 31, 2015, differed from normal daily temperatures. Therefore, to reflect normal weather, daily peak and average net system loads are each adjusted independently, but using the same methodology.

Daily average load is the summation of the hourly load for the day divided by twenty-four hours. Daily peak is the maximum hourly load for the day. Staff uses separate regression models to estimate both (1) a base component, which is allowed to fluctuate across time as non-weather factors, and (2) a weather-sensitive component, which measures the response to daily fluctuations in weather for daily average loads and peak loads. Independent regression models are necessary because daily average loads respond differently to weather than peak loads. The models' regression parameters, along with the difference between normal and actual cooling and heating measures, are used to calculate weather adjustments to both the average and peak loads for each day. The adjustments for each day are added respectively to the actual average and to the peak loads of each day. The starting point for allocating the weather-normalized daily peak and average loads to the hours is the actual hourly loads for the year being normalized. A unitized load curve[79] is calculated for each day as a function of the actual peak and average loads for that day. Staff uses the corresponding weather-normalized daily peak and average loads, along with the unitized load curves, to calculate weather-normalized hourly loads for each hour of the year.

This process includes many checks and balances, which are included in the spreadsheets that are used by Staff. In addition, the analyst is required to examine the data at several points in the process. For more information, the process is described in greater detail in the document "Weather Normalization of Electric Loads, Part A: Hourly Net System Loads."[80]

After weather-normalizing and annualizing usage for GMO's retail customer classes is completed, weather-normalized wholesale usage is added to produce an annual sum of the hourly net system loads that equals the adjusted test year usage, plus losses, and is consistent with Staff's normalized revenues.

Staff applies a factor to each hour of the weather-normalized loads to produce an annual sum of the hourly net-system loads that equals the usage, plus losses, consistent with normalized revenues. Once completed, the hourly normalized system loads were used in developing fuel and purchased power expense. Staff witness Alan J. Bax also used the annual requirement of the net system load in developing the Staff's jurisdictional energy allocator.

Staff Experts/Witnesses: Seoung Joun Won, PhD

11. System Energy Losses

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

[79] A unitized load curve is a set of 24 hourly loads of a given day by subtracting the average daily load from each hourly load, then dividing by the difference between the peak and the average so that the average of the calculated hourly loads is 0 and the peak is 1.

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

The basis for calculating system energy losses is that Net System Input ("NSI") equals the sum of "Retail Sales" + "Wholesale Sales" + "Company Use" and "System Energy Losses." This can be expressed mathematically as:

NSI = Retail Sales + Wholesale Sales + Company Use + System Energy Losses.

NSI, Retail and Wholesale Sales and Company Use are known quantities; therefore, system energy losses may be calculated as follows:

System Energy Losses = NSI – (Retail Sales + Wholesale Sales + Company Use).

The system energy loss percentage is the ratio of system energy losses to NSI, multiplied by 100:

System Energy Loss Percentage = (System Energy Losses ÷ NSI) X 100.

NSI is also equal to the sum of the Company's net generation and net interchange. Net interchange is the difference between off-system purchases and off-system sales. Net generation is the total energy output of each generating unit minus the energy consumed internally to enable the production of electricity at each plant. The output of each generating plant is monitored and metered continuously. The net of off-system purchases and off-system sales ("Net Interchange") is also similarly monitored.

System energy loss factors were calculated for GMO on a company-wide basis and for GMO's MPS and L&P rate districts. The following system energy loss percentages were calculated based upon an analysis of data from the twelve-month period ending December 31, 2015:

GMO	0.0671
MPS Rate District	0.0665
L&P Rate District	0.0687

Staff witness Seoung Joun Won used these system energy loss factors in his determination of hourly loads that are utilized in developing Staff's fuel model.

Staff Expert/Witness: Alan J. Bax

12. Loss Study as it Applies to the Fuel Adjustment Clause

In this case, GMO supplied Staff with a loss study in the workpapers of GMO witness Tim Rush. This is the same loss study provided to Staff in October 2014 in conjunction with the request of KCPL to establish a Fuel Adjustment Clause ("FAC") in Case No. ER-2014-0370. While this loss study meets the requirement stated in 4 CSR 240-20.090(9) that GMO supply a current loss study in conjunction with its request to continue its FAC in the current rate case, the resulting loss factors calculated for GMO's individual MPS and L&P rate districts are questionable, as compared to results of previous loss studies. Moreover, while this loss study contained a separate analysis of losses for both GMO's MPS and L&P rate districts, an analysis considering the combination of the two rate districts, (a consolidated GMO system), was not included.

A supplemental spreadsheet to this loss study was provided by GMO, which was described as illustrating a loss analysis of a consolidated GMO system. This analysis was said to be determined in part by combining the data reported for the individual MPS and L&P rate districts. The loss analysis of the individual MPS and L&P rate districts was determined utilizing data collected during calendar year 2013.

In comparing the results of the most recent loss study received in October 2014 to the immediately previous loss study received in October 2009, Staff notes the approximate 15% change in the total losses between the two studies reported for both the MPS and the L&P rate districts. Furthermore, in addition to the unusual change in magnitude of the losses reported in these two loss studies, the reported losses for the MPS rate district increased by this amount while the reported losses for the L&P rate district decreased by a similar amount. This resulted in a nearly 2% difference between the overall loss percentage reported between the MPS and L&P rate districts. Historically, there has been little variance between the loss percentages of MPS and L&P rate districts. The corresponding difference between the loss percentages of the MPS and L&P rate districts in the 2009 loss study is 0.11% as compared to the nearly 2% difference in the 2014 study.

In its response to Staff's Data Request No. 0280, GMO says that these unusual results between two successive loss studies most likely are due in large part to a reassignment of distribution transformers and other equipment from "one GMO company to the other." Staff understands this to mean GMO reassigned equipment from one rate district to the other.

Staff has requested more in-depth details regarding these reassignments, but has yet to receive any additional detail regarding these reassignments. Without a thorough explanation of the unusual results contained in the latest loss study, Staff is utilizing the results of the previous 2009 loss study in its corresponding analyses regarding GMO's FAC.

Staff Expert/Witness: Alan J. Bax

C. Payroll, Payroll Related Benefits including 401k Benefit Costs

1. Payroll Costs

Staff has examined the payroll costs of KCPL and recommends distributing its annualized payroll using ratios derived from the existing payroll distribution of GMO's recorded payroll costs during the test year. Staff recommends annualizing KCPL's payroll expense using actual employee levels as of the end of the update period, December 31, 2015, plus the directly assigned Jeffrey Energy Center payroll, which generating station is jointly-owned by Westar Energy (92%) and GMO (8%). Because GMO does not have any employees, KCPL employees perform all services for Great Plains, KCPL and GMO, including; GMO's MPS rate district, GMO's L&P rate district, L&P's steam operations, and certain portions of KCPL's non-regulated enterprises. Since KCPL employees perform all services for Great Plains and its subsidiaries, an allocation of KCPL's payroll costs is necessary to assign the proper amounts of payroll costs to each of the Great Plains entities, including GMO. Staff has reviewed KCPL's allocation of actual payroll assigned to each of these entities and allocated annualized payroll based on this allocation.

Staff annualized payroll costs in this case using actual employee levels as of the end of the update period on December 31, 2015. Each employee's individual salary was summed to compute the total GPE and KCPL payroll costs on an annual basis. Annualized payroll included differential and premium pay, which are wage adders for second and third shift employees, paid to KCPL employees based on union contracts.

Overtime payroll for GMO was calculated using a four-year average of historical costs. A review of prior overtime expense shows a steady increase in overtime dollars and overtime hours from 2012 through 2014, but also shows a spike in overtime costs in 2015. Under normal circumstances, an upward trend in a cost would warrant the inclusion of the last known amount, but in this case, the last known amount (2015) is an outlying data point caused by a storm and an outage. Staff recommends using a four-year average of overtime costs since the result recognizes the upward trend in overtime (includes 2015 in the average) but smooths out the irregular overtime costs experienced during the most recent period (2015).

As the result of KCPL's ownership and operating agreements for several generating facilities with several partners, it is necessary to assign payroll costs to these partners and remove the related payroll costs from the payroll annualization that is reflected in the revenue requirement calculations. This assignment of joint partner billings is necessary to ensure that payroll costs properly billed to the joint partners are not included in the KCPL and GMO rate districts' payroll costs. Staff reviewed the actual joint partner billings during the previous three years (2013 – 2015) and found the total amount fluctuated. Therefore, Staff included a three-year average of joint partner billings in GMO's payroll annualization.

It is also necessary to remove an amount of payroll that is recovered outside of base rates. In GMO's case, payroll is charged to, and subsequently recovered from, ratepayers via the Missouri Energy Efficiency Investment Act ("MEEIA") rider. Both KCPL and GMO have a MEEIA rider currently in effect. Staff examined the amount of payroll historically charged to the MEEIA recovery mechanisms and normalized the monthly costs during the period of January 1, 2015, through May 31, 2016. After obtaining a normalized monthly cost, Staff annualized the cost for a 12-month period and removed the annualized amount from KCPL's total company labor.

The total annualized GPE and KCPL payroll costs allocated to GMO also have to be allocated to operational and maintenance ("O&M") expense and other costs. The vast majority of non-O&M costs are related to construction (capital) but also include non-regulated functions of a company. The construction amounts are payroll costs assigned to the work orders during construction projects. The amounts that are included in the revenue requirement calculations for GMO are the levels assigned to payroll expenses through the O&M expense ratios which are developed by comparing O&M labor to total labor. Staff O&M expense ratios are calculated by averaging the ratios of 2013 – 2015 actual results.

Staff distributed the adjustment for payroll by the individual FERC account based upon the existing test year distribution in adjustments: E-5.1, 12.1, 14.1, 16.1, 17.1, 25.1, 26.1, 27.1, 28.1, 29.1, 45.1, 53.1, 54.1, 55.1, 58.1, 59.1, 60.1, 61.1, 70.1, 71.1, 77.1, 78.1, 79.1, 80.1, 83.1, 87.1, 89.1, 90.1, 91.1, 98.1, 99.1, 100.1, 101.1, 102.1, 104.1, 105.1, 106.1, 111.1, 112.1, 113.1, 114.1, 115.1, 116.1, 117.1, 118.1, 119.1, 124.1, 125.1, 126.1, 128.1, 132.1, 133.1, 135.1, 139.1, 145.1, 146.1, 147.1, 150.1, 151.1, 156.1, 159.1, 165.1.

Staff Expert/Witness: Matthew R. Young

2. Payroll Related Benefits

GMO incurs costs, allocated from KCPL, for a variety of payroll-related benefits such as 401k matching and employee insurance premium contributions. To annualize GMO's 401k expense, Staff calculated a 401k matching rate ratio by dividing KCPL's actual 401k match by the actual 401k eligible payroll expense in five separate pay periods and averaging those ratios. Staff then applied the average matching rate to its annualized payroll amounts that incur 401k matching expense. This annualized expense is reflected in Staff Adjustment E-151.4.

For the remaining payroll benefits, Staff annualized the 12-month period expenses ended December 31, 2015, and allocated the amounts to joint partners and Great Plains jurisdictions using the same method used to allocate payroll expense (described in the payroll section of this Staff Report). Staff's annualized payroll benefits are reflected in Adjustment E-151.6.

Staff Expert/Witness: Matthew R. Young

3. Payroll Taxes

Payroll taxes were annualized by applying current payroll tax rates to each employee's annual level of base payroll and the last known receipt of Value-Link incentive compensation. To calculate payroll taxes on executive incentive compensation, Staff applied the current tax rate for Medicare tax to its annualized executive incentive compensation under the assumption the all tax wage ceilings were achieved through base payroll. To compute payroll taxes for overtime, temporary labor, premium pay, and joint partner billings, Staff applied the current payroll tax rates to these "other" wages assuming the Federal Unemployment Tax Act ("FUTA") and State Unemployment Tax Act ("SUTA") wages ceilings have been achieved. Staff also recognized an allocation of payroll taxes to the MEEIA recovery mechanism using the same methodology described in the payroll section. Adjustment E-182.3 reflects annualized payroll taxes based on payroll costs as of December 31, 2015.

Staff Expert/Witness: Matthew R. Young

4. True-up of Payroll Costs

Staff will update the total payroll costs for the true-up in this case, which is based on an update period of July 31, 2016. The same methodology used to annualize payroll as of December 31, 2015, will be used for the July 31, 2016, true-up.

Staff Expert/Witness: Matthew R. Young

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

Staff and KCPL entered into an agreement in GMO's 2012 rate case (File No. ER-2012-0175) titled, *Non-Unanimous Stipulation and Agreement As To Certain Issues* dated October 19, 2012. Among other items, this agreement addressed the ratemaking treatment for annual pension costs under Financial Accounting Standard No. 87 ("FAS 87") and pension settlement and curtailment accounting under Financial Accounting Standard No. 88 ("FAS 88").

The names of the Financial Accounting Standards have recently changed. The Accounting Standards Codification project of the Financial Accounting Standards Board ("FASB") was launched in 2009 and became the single source of authoritative non-governmental U.S. Generally Accepted Accounting Principles ("GAAP") (other than guidance issued by the Securities and Exchange Commission). The new "Codification Topic 715" covers all of the following FAS statements under its various subtopics:

- FAS 87 and FAS 88, Employers' Accounting for Pensions;
- FAS 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans; and
- FAS 106, Employers' Accounting for Postretirement Benefits other than Pensions.

While the above individual FAS statements have been combined into Codification Topic 715, Staff, for the purposes of this Report, will use the original FAS statement numbers for FAS 87, FAS 88, FAS 106 and FAS 158, as needed.

The agreement in File No. ER-2012-0175 affirmed the prior provisions regarding the same matters reached in the stipulation and agreement attained in Case No. ER-2010-0356. The agreement in File No. ER-2012-0175 also addressed the ratemaking treatment for a pension curtailment or settlement recognized under FAS 88.

There are two amounts in GMO's rate base relating to agreements regarding pension regulatory assets reached in the various agreements attained in Case Nos. ER-2007-0007, ER-2009-0090, ER-2010-0356, and ER-2012-0175:

1) ERISA Minimum Tracker – This balance is the remaining tracked amount from the prior pension tracking method.
2) A FAS 87 Regulatory Asset – Under the terms of the agreements referenced above, the difference between FAS 87 reflected in rates and GMO's actual cost recorded in its financial statements is tracked and recorded as either a regulatory asset or liability, and is then amortized over five years in the next rate case. GMO's rate base includes a regulatory asset as of December 31, 2015.

Staff's recommended annualized level of GMO pension expense is based on information provided by KCPL's actuarial firm, Towers Watson, which KCPL in turn provided to Staff in response to Staff Data Request No. 0133. Staff's calculation of GMO's pension expense was made in accordance with the methodology described in the agreement reached in File No. ER-2012-0175.

Based on the language of the agreement in File No. ER-2012-0175, Staff recommends cost-of-service recovery of GMO's share of FAS 88 charges through a five-year amortization increase to pension expense.

The FAS 88 charge is related to the impact on pension expense of employees being removed from GMO's pension plans and the impact of paying lump sum pension distributions to these employees in the alternative. While the FAS 88 charge is an immediate increase to cost of service, the future ongoing level of pension expense should be lower due to the removal of these employees' costs from the pension plan.

Ongoing pension expense and the rate base portion of the pension tracker mechanism are included in Staff's Accounting Schedule 9, and Rate Base – Schedule 2.

Staff Expert/Witness: Keith Majors

6. <u>FAS 106 – Other Postretirement Benefit Costs ("OPEBs") and OPEB Tracker Regulatory Liability</u>

Other Post Employment Benefit Costs ("OPEBs") are those costs GMO incurs to provide certain benefits to GMO retirees. The primary benefit is medical insurance, but these costs also include life, dental and vision insurance benefits. Historically, OPEBs have been calculated by GMO's actuaries under the terms of Financial Accounting Standard 106 ("FAS 106").

FAS 106 is the FASB approved accrual accounting method used for financial statement recognition of annual OPEBs. The accounting of the cost of postretirement benefits is not based on the actual dollars GMO pays for OPEBs to its retirees currently, but under FAS 106 is accrual-based, in that it attempts to recognize the financial effects of noncash transactions and events as they occur. These noncash transactions and events are primarily current benefits earned by employees before retirement, but not paid until after retirement, as well as the interest cost arising from the passage of time until those benefits are paid.

Staff's OPEB adjustment to GMO Account 926, Employee Benefits, annualizes the level of OPEBs expense determined by GMO's actuaries using the FAS 106 accounting method, calculated as the 12 months ending December 31, 2014, actual payments.

Beginning June 25, 2011, GMO initiated a new tracker for OPEBs which the Commission authorized in Case No. ER-2010-0356. What is tracked are the differences between the current ongoing level of OPEBs expense funded by GMO in an external trust and the dollar amount of OPEBs expense reflected in rates in each case. The unamortized balance of this tracker will be amortized over five years in each successive rate case, and either will be added to or subtracted from the level of OPEBs expense as determined by GMO's actuaries. As with other rate base, prepaid pension and other pension assets, it is anticipated that the OPEBs tracker liability will be updated through the July 31, 2016, true-up period.

Ongoing OPEBs expense and the rate base portion of the OPEBs tracker mechanism are included in Staff's Accounting Schedule 9, and Rate Base – Schedule 2.

Staff Expert/Witness: Keith Majors

7. Supplemental Executive Retirement Plan ("SERP") Expense

Included in Staff's revenue requirement recommendation is an annualized level of actual monthly-recurring supplemental executive retirement plan ("SERP") payments GMO made to its former executives and other highly-compensated former employees. SERPs are non-qualified retirement plans for officers and executives, which provide pension benefits these highly-compensated individuals would have received under other company retirement plans but for compensation and benefit limits imposed by the Internal Revenue Service ("IRS"). These supplemental pension benefits paid to retired former officers and executives are in addition to the cost of pension benefits KCPL pays under its all-employee FAS 87 pension plan. SERP pension benefits generally exceed various limits imposed on retirement programs by the IRS and therefore are referred to as "non-qualified" plans. SERP benefits are not externally funded by GMO and the amounts Staff included in GMO's cost of service are based upon actual cash SERP payouts to covered employees.

SERP payments consist of monthly annuity payments to some recipients and periodic lump-sum distributions to others. Lump-sum payments can be significant and are often difficult to predict. As opposed to including a normalized amount of actual lump-sum payments, GMO used a conversion factor of 14.3 to convert prior lump-sum payments to an amount that approximates the equivalent annuity payments to the qualifying employees as if that lump-sum payment option were not elected. Staff utilized this factor for the calculation of a normalized level of converted lump-sum payments.

Staff recommends that a three-year average of monthly annuity payments and a three-year average of converted lump-sum payments be used in this rate case to determine allowable SERP expense in rates. This recommendation is reflected in Staff's revenue requirement on Accounting Schedule 9.

Staff Expert/Witness: Keith Majors

8. <u>Short Term Annual Incentive Compensation</u>

KCPL has two separate, short-term annual incentive compensation plans for executive and other non-union employees, with a portion of the costs associated with those plans being allocated to the GMO rate districts using the same allocations as the payroll expense adjustment, because GMO has no employees of its own. These plans are designed to grant cash awards of various amounts calculated upon designated annual metrics. The timing of the payout for amounts accrued under the terms of each plan for a calendar year is during the first quarter of the following calendar year. The two incentive compensation plans are: (1) the Value-Link Plan, reserved for non-executive, non-union KCPL employees and (2) the Annual Executive Incentive Plan, reserved for senior KCPL management employees.

The incentive plans all have benchmarks to identify targets that KCPL employees are expected to achieve before any cash payouts are awarded. These targets are reevaluated each calendar year and communicated to the employees early enough so that the employees have sufficient opportunity to achieve the benchmarks.

The Value-Link Plan was implemented to provide an incentive for the achievement of defined annual results of KCPL and its business units by non-executive, non-union KCPL employees. **

**

The Commission has historically disallowed incentive compensation awards tied to the achievement of certain corporate financial measures on the basis that these measures provide no tangible benefit to Missouri ratepayers. *See* specifically *Re KCPL*, Case No. ER-2006-0314, 15 Mo.P.S.C.3d 138, 171-72 (2006) and *Re KCPL*, Case No. ER-2007-0291, 15 Mo.P.S.C.3d 552, 585-87 (2007). However, after reviewing the Value-Link payouts for plan years 2012 through 2015, Staff notes that the ** ____ ______________ **

The second short-term annual incentive plan is the Annual Incentive Plan which is designed to motivate and reward senior management to achieve specific key financial and business goals and to also reward individual performance of senior KCPL management. ** ____ ______________________________ **

Adjustments E-5.2, 45.2, 71.2, 98.3, 106.4, 124.2, 125.2, 126.4, 135.5, 145.7 and 151.5.

Staff Expert/Witness: Matthew R. Young

9. Long-Term Incentive Compensation

GMO proposed to remove the costs from the Long-Term Incentive Compensation Plan for its officers in Case No. ER-2016-0156 via GMO adjustment CS-11. The Staff agrees with this proposal, and has also made the adjustment to remove the Long-Term Incentive Compensation Plan from this case.

Staff Expert/Witness: Matthew R. Young

10. Capitalized Long-Term Incentive Equity Compensation

Great Plains offers an equity-based Long Term Incentive Plan ("LTIP"), the cost of which is partially allocated to GMO. Staff has removed the test year expense portion of the LTIP recorded in the test year ended June 30, 2015. The Commission denied recovery of stock-based compensation in its Report and Order in KCPL Case Nos. ER-2006-0314, 15 Mo.P.S.C.3d 138, 171-72 (2006) and ER-2007-0291, 15 Mo.P.S.C.3d 552, 585-87 (2007). In Case Nos. ER-2010-356 and ER-2012-0175, GMO voluntarily removed costs related to the LTIP from the cost of service. In its *Report and Order* in KCPL File No. ER-2014-0370 at page 68, the Commission noted that "[u]tility expenses that are highly discretionary and do not benefit customers, such as charitable donations, political lobbying expenses, and incentive compensation tied to earnings per share, are typically allocated entirely to shareholders." (Footnote omitted).

Beginning in 2014, GMO began charging to capital accounts a portion of the allocated LTIP expense. Prior to 2014, no portion of this expense was capitalized to plant accounts. Because stock-based compensation is not appropriate to be recovered as an expense in the cost of service, neither should it be recovered as a portion of plant in service included in rate base. Therefore, Staff recommends the amount of LTIP capitalized should be removed from plant in service. Staff's adjustment is included in Staff's Accounting Schedule 3 – Plant In Service, Adjustment P-418.1, P-419.1 and P-434.1.

Staff Expert/Witness: Keith Majors

D. Maintenance Normalization Adjustments

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

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

Staff analyzed maintenance costs from 2001 through December 31, 2015, by functional area for production, transmission, distribution, and general plant by FERC account. Since labor costs are separately addressed by the payroll adjustment to the cost of service, labor costs were removed from Staff's maintenance analysis in order to perform a review of non-labor maintenance costs only.

Several steps were taken to analyze the maintenance data. They included examining the non-labor maintenance amounts to identify any characteristics of the maintenance dollars such as trends or fluctuations from one period to another. Another approach used by Staff was to compare functional averages, which included calculating a two-year through seven-year averages of maintenance costs to determine if there were fluctuations within each functional area. Each of the costs by year and averages for maintenance were also compared to the test year ended June 30, 2015, and the known and measurable update period ended December 31, 2015. Staff reviewed the data as detailed above to establish a maintenance level that will result in a reasonable estimate of the annual level of the Company's future maintenance costs.

Beginning with GMO Case No. ER-2010-0356, Staff had performed a separate analysis for Iatan Unit 2 production maintenance expense. In prior cases, Iatan Unit 2 did not have historical data to analyze because the unit was too new. Now that the unit has been operating for nearly six years, Staff included Iatan Unit 2 maintenance costs in its analysis of historical production maintenance expense.

Staff results are presented in the following table:

Maintenance Category	Adjustment Method
Steam Production	3 year average of 2013-2015
Other Production	3 year average of 2013-2015
Transmission	12 months ended December 31, 2015
Distribution	3 year average of 2013-2015
General	12 months ended June 30, 2015

The adjustments that reflect Staff's results are E-25.2, E-26.2, E-27.2, E-28.2, E-29.2, E-58.2, E-59.2, E-60.2, E-61.2, E-87.2, E-89.2, E-90.2, E-91.2, E-92.2, E-111.2, E-112.2, E-113.2, E-114.2, E-115.2, E-116.2, E-117.2 and E-118.2 and can be found in Staff's GMO consolidated Accounting Schedules. Staff also made adjustment E-60.3 to remove over-accrued maintenance expense for the South Harper generation station.

Staff Expert/Witness: Matthew R. Young

1. <u>Meter Replacement Program – Incremental Meter Reading Costs</u>

As GMO transitions from manually-read meters to Advance Metering Infrastructure ("AMI") meters, GMO will incur increased costs related to meter reading. The current meter installation program is discussed in more detail by Staff Expert Witness Jerry Scheible in the section titled "Smart Meter Installation." Staff has included the costs based on the current per-meter reading fee multiplied by the number of AMI meters installed as of December 31, 2015. To utilize the full functionality of the AMI meters, a third party was procured to assist in the data collection of customer usage. This outside service increases GMO's cost of service and will result in a higher cost increase by the true-up period in this case, July 31, 2016. Staff also expects to see cost decreases as a result of this initiative, notably payroll decreases for meter reading labor, and will include both cost increases and decreases in the overall true-up revenue requirement.

As of December 31, 2015, GMO's customer usage is largely measured by meters that need to be manually read. These manual-read meters existed throughout the GMO territory when Great Plains acquired Aquila in 2007, and the meter technology has not been upgraded since that time. To explain the lack of upgrades to the system, please see KCPL's response to Staff Data Request No. 0259 in Case No. ER-2010-0355:

> At the time of the Acquisition, reflected in Case No. EM-2007-0374, AMR [Automated Meter Reading] was a proven technology and KCP&L had ten-years of practical experience implementing and managing the complexities required to capture AMR operational efficiencies. Even then, the Company was to seek agreement of regulators and shareholders—that the AMR project was a capital priority within the portfolio of capital investment alternatives.
>
> As early planning of AMR implementation in GMO began, KCP&L, based on its implementation and management experience of AMR projects, called into question whether AMR was the direction to go or should an alternative, Advance Metering Infrastructure ("AMI") technology, be advanced in GMO?
>
> The potential of AMI technological advances, in combination with anticipated future expansion of energy efficiency and demand response requirements, highlighted the superiority of AMI systems over existing AMR systems in functionality, reliability, and customer benefits. In light of AMI's potential customer benefits and technological superiority over AMR systems, KCP&L began considering implementation of AMI technology throughout GMO and KCP&L's service territories.
>
> In the Direct Testimony of Edward C. Matthews in Case Nos. ER-2009-0089 and ER-2009-0090 ("KCP&L 2009 Rate Case" and "GMO 2009 Rate Case", respectively), he provides a summary discussion of the benefits of AMI technology and how it potentially impacts customer service and expands energy efficiency and demand response opportunities. Mr. Matthews also sets out a timeline for installation of AMI in KCP&L-MO and GMO service territories.

> The schedule set out in Mr. Matthews' testimony was, for all intents and purposes, suspended when in early 2009 KCP&L identified an opportunity to support the cost of real world testing of AMI technology—without impact to ratepayers—by applying for and securing an American Recovery and Reinvestment Act ("ARRA") demonstration grant. Although the U.S. Department of Energy informs the Company that the ARRA grant is awarded to KCP&L for the demonstration project, the final agreement is expected to be executed shortly. The grant supports the Green Impact Zone project that will enable an extensive evaluation of AMI benefits not only for KCP&L and GMO customers, but the information will be shared more broadly with Missouri utilities and other utilities interested in introducing AMI technology.

At the time of GMO's 2010 rate case (Case No. ER-2010-0356) and continuing into GMO's 2012 rate case (Case No. ER-2012-0175), GMO believed it was prudent to outsource meter-reading activities to "maintain staffing flexibility" until a decision was made regarding future metering technology.[81] By the conclusion of ER-2012-0175, the decision was made to cease outsourcing meter reading and utilize internal and temporary labor to read the meters for GMO's customers.[82]

On April 5, 2013, an agreement was made between GPES and Landis+Gyr Technology, Inc. ("Supplier") to provide service necessary to operate AMI meters in all of the Great Plains territories. Although the agreement was made in 2013, the meter installation program did not begin in earnest until early 2016 for GMO's service territory. The agreement specifies a price per meter of ** ____ ** payable to the Supplier in exchange for certain data transfer services between the AMI meters and GMO.

When comparing this new expense for GMO to the expense incurred by KCPL under the same contract, it is necessary to recognize the difference in each company's existing meter-reading costs. Since GMO's current meters are not AMR or AMI meters, they must be read manually by internal employees; the ** ____ ** per meter contractual cost is <u>new</u> to GMO. This manual reading is in contrast with KCPL, which had existing AMR meters before the upgrade to AMI. To read the existing AMR meters, KCPL had a contract in place for ** ____ ** per meter and when the AMI upgrade was performed, the per-meter cost rose to ** ____ **.

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[81] See GMO response to Staff Data Request No. 0254, Case No. ER-2010-0356.

[82] See 5/27/2016 GMO response to Staff Data Request No. 0338, Case No. ER-2016-0156.

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KCPL's cost increase for AMI meter reading did not affect other portions of the cost of service. Unlike KCPL, GMO's going-forward method of reading meters is likely to result in decreases to other costs, namely labor currently used to manually read meters. Staff intends to true-up the costs of GMO's AMI meter reading (Adjustment E-125.2), since the number of installations completed will increase by July 31, 2016, the true-up date in this case. Staff will also examine other cost-of-service components for other cost impacts resulting from the AMI meter reading agreement.

Staff Expert/Witness: Matthew R. Young

2. Iatan Unit 2 O&M Expenses

In Case No. ER-2010-0356, Staff recommended a tracker mechanism be used for Iatan Unit 2 O&M expense, so the actual cost of the O&M expense related to Iatan Unit 2 would be recovered through rates for the benefit of both ratepayers and GMO in future rate cases. Since Iatan Unit 2 was placed in service on August 26, 2010, and GMO's operational experience with Iatan Unit 2 was non-existent at the time of Case No. ER-2010-0356, an O&M tracker was suggested to protect both GMO and its customers from including projected costs in rates that would, in all likelihood, vary from the actual costs associated with Iatan Unit 2's O&M expense. GMO and other signatory parties agreed through a *Non-Unanimous Stipulation and Agreement* in Case No. ER-2010-0356 to establish a tracker for Iatan Unit 2 costs, and on April 12, 2011, the Commission approved the use of a tracker for these costs.

In Case No. ER-2012-0175, a three-year amortization of the actual Iatan Unit 2 costs that exceeded the base rates established in Case No. ER-2010-0356 was included in GMO's cost of service. In addition, a new base level was established for the Iatan Unit 2 tracker and also included in GMO's cost of service on a going-forward basis. At the time of the 2012 rate case, GMO still only had limited operating experience with the two year old plant.

In this case, Staff is proposing the recovery of the excess costs over the base amount established in Case No. ER-2012-0175. Staff is proposing a four-year amortization of the excess costs over the base amount. Adjustments reflecting one-third of the total unrecovered costs are reflected in Accounting Schedule 9, in Adjustments E-5.3 and E-27.3.

As previously mentioned, Iatan Unit 2 was placed in service on August 26, 2010. At the end of the true-up period in this case, July 31, 2016, the plant will have operated for nearly six years. As a result, Staff is recommending that this tracker be discontinued, since a level of historical O&M expense has been established for Iatan Unit 2 and common operations. During subsequent audits and examination, Staff should treat Iatan Unit 2 and common costs as a normal component of O&M expense in the cost of service just like it does with all the other power plants operated by GMO.

Also, as previously discussed, a three-year amortization of the excess Iatan Unit 2 O&M expense over the base amount established in Case No. ER-2010-0356 was included in GMO's cost of service in Case NO. ER-2012-0175. The effective date of rates in Case No. ER-2012-0175 was January 26, 2013. The amortization period for these costs ended three years later on January 25, 2016. Given the limited experience with operating and maintaining Iatan Unit 2 when it was placed in service, a maintenance tracker was established to protect both GMO and its customers from a material difference between amounts collected and amounts spent for Iatan Unit 2 O&M costs. The tracker was not intended to allow GMO to continue to collect rates in excess of the Iatan Unit 2 deferred costs.

In this case, Staff has calculated an amount related to the over-recovery from the amortization included in rates set in Case No. ER-2012-0175 to offset current deferred Iatan Unit 2 costs. Additionally, Staff recommends that the Commission require GMO to track any over-recovery associated with the new amortization established in the current case for consideration in the next GMO rate case.

Staff Expert/Witness: Matthew R. Young

3. **<u>IT Software Maintenance</u>**

GMO incurs costs associated with contracts to maintain its information technology ("IT") hardware and software that include but are not limited to, Microsoft, PowerPlan, and Oracle. GMO enters into prepayment for the contracts and amortizes the balance of the costs over the life of the contract. Staff reviewed GMO's prepaid IT software maintenance for the update period in this case, 12 months ending December 31, 2015. During its review, Staff found that GMO renewed several contracts in 2015. If a contract was renewed, Staff included the current contract price in its annualization and omitted contracts that expired in 2015 and were not subsequently renewed.

Staff's adjustment is identified on Schedule 9 of Staff's GMO Consolidated and MPS and L&P Accounting Schedules, Adjustments E-17.2, E-72.1, E-83.2, E-118.2, E-127.2 and E-161.3. Staff will review this adjustment during the True-Up audit in this case.

Staff Expert/Witness: Karen Lyons

4. Critical Infrastructure Protection and Cyber-Security

Staff analyzed GMO's actual non-labor Cyber-Security and Critical Infrastructure Protection ("CIP") costs from the period of 2009 through 2015. The North American Electric Reliability Corporation ("NERC") established a set of requirements designed to secure utility assets that are required for operating North America's bulk electric system. GMO's historical Cyber-Security and CIP non-labor costs are identified in the following table:

GMO Non-Labor CIP and Cyber-Security Costs							
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
CIP	$41,666	$136,120	$339,055	$377,108	$613,709	$1,735,913	$1,527,779
Cyber-Security	215,685	213,240	212,958	307,312	222,789	320,258	470,522
Total	**$257,351**	**$349,360**	**$552,014**	**$684,420**	**$836,495**	**$2,056,171**	**$1,998,301**

Staff found the costs for CIP and Cyber-Security showed an upward trend through December 31, 2014, and leveled off in December 2015. Consequently, Staff annualized the non-labor CIP and Cyber-Security costs as of December 31, 2015. Consistent with other rate case expenses, Staff did not include internal labor costs for CIP and Cyber-Security as those are included in the cost of service through Staff's payroll annualization. Staff's adjustments are identified on Schedule 9 of Staff's GMO consolidated, MPS and L&P Accounting Schedules, Adjustments E-145.3, E-147.3 and E-161.4. Staff will review this adjustment during the True-Up audit in this case.

Staff Expert/Witness: Karen Lyons

E. Other Non-Labor Adjustments

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

KCPL and GMO sell all of their electric accounts receivable to their wholly-owned subsidiaries, KCPL Receivables Company and GMO Receivables Company, respectively, which in turn sell an undivided percentage ownership interest in the accounts receivable to Victory Receivables Corporation, an independent outside investor. Each of KCPL Receivables Company's and GMO Receivables Company's sales of the undivided percentage ownership interest in accounts receivable to Victory Receivables Corporation is accounted for as a secured borrowing with accounts receivable pledged as collateral and a corresponding short-term collateralized note payable recognized on the balance sheets.

As a result of this arrangement, there is no bad debt expense on GMO's test year books and records. Therefore, an adjustment to GMO's test year for the amount of bad debt expense recorded on the books and records of GMO Receivables Company is necessary to reflect in customer rates an appropriate amount of this utility expense.

Staff's adjustments are identified on Schedule 9 of Staff's GMO consolidated, MPS, and L&P Accounting Schedules, Adjustment E-127.1.

Staff Expert/Witness: Keith Majors

a. Bad Debt Expense Annualization

Staff's recommended treatment of bad debt expense is to calculate the ratio of GMO's net write-offs to annualized retail revenue to determine an appropriate level of bad debt expense. Bad debt expense is the portion of retail revenues GMO is unable to collect from retail customers by reason of bill non-payment. After a certain amount of time has passed, delinquent customer accounts are written-off and turned over to a third party collection agency for recovery. If GMO is subsequently able to successfully collect some portion of previously written off delinquent amounts owed, then those amounts collected reduce the actual write-offs. This results in the net write-offs which are used to determine the annualized levels of bad debt expense for GMO.

Staff calculated the annualized bad debt expense by examining the billed revenues, net of gross receipt taxes for the twelve months ending June 30, 2015, and actual 12-month history of billed revenues that were never collected (actual net write-offs) for the twelve months ending December 31, 2015. From this information a bad debt ratio was derived, which was then applied to Staff's annualized level of retail revenues for GMO's MPS and L&P rate districts to obtain the annualized levels of bad debt expense for each rate district. The annualized levels of bad debt expense for GMO's MPS and L&P rate districts were summed to derive GMO's consolidated level of bad debt expense. The apparent lag time between the net retail sales and actual net write-offs in Staff's calculation is consistent with GMO's adjustment to annualize bad debt expense.

GMO asserts that it takes approximately six months for a customer's unpaid bill to be written off after the customer receives service. Staff's adjustment for bad debt expense adjusts the test year results to reflect a level of bad debt expense that is consistent with Staff's annualized level of retail revenue.

Staff's adjustments are identified on Schedule 9 of Staff's GMO consolidated, MPS and L&P Accounting Schedules, Adjustment E-127.2.

Staff Expert/Witness: Keith Majors

2. <u>Advertising Expense</u>

In forming its recommendation of the allowable level of advertising expense, Staff relied on the principles the Commission propounded within the 1985 Kansas City Power & Light rate case, Case No. ER-85-185: *In Re: Kansas City Power and Light Company,* 28 MO P.S.C. (N.S.) 228 (1986), in which the Commission adopted an approach that classifies advertisements into five categories and provides separate rate treatment for each category. The five categories of advertisements recognized by the Commission are:

1. General: advertising that is useful in the provision of adequate service;
2. Safety: advertising which conveys the ways to safely use electricity and to avoid accidents;
3. Promotional: advertising used to encourage or promote the use of electricity;
4. Institutional: advertising used to improve the company's public image; and
5. Political: advertising associated with political issues.

The Commission adopted these categories of advertisements because a utility's revenue requirement should: 1) always include the reasonable and necessary cost of general and safety advertisements; 2) never include the cost of institutional or political advertisements; and

3) include the cost of promotional advertisements only to the extent that the utility can provide cost-justification for the advertisement (*Report and Order* in KCPL Case No. EO-85-185, 28 Mo.P.S.C. (N.S.) 228, 269-271 (April 23, 1986)). In response to data requests issued in this case, GMO provided a list of all costs associated with advertising and a brief description of those costs. The purpose of Staff's review of GMO's advertising costs was to ensure that only advertising costs for programs necessary for the provision of safe and adequate utility service are included in GMO's cost of service. For example, all direct and indirect costs associated with safety advertising were included as well as other costs necessary for GMO to communicate with its customers on utility matters (i.e., general advertising). Staff focused on advertising campaigns, not just individual advertisements, which is consistent with the Commission's decision in its Order for Ameren Missouri in Case No. ER-2008-0318.

GMO is allowed to recover some advertising expenses related to MEEIA through its authorized MEEIA surcharge. As these advertising expenses are recovered outside of base rates GMO removed a large portion of these expenses from the cost of service. However, Staff found an additional amount of MEEIA advertising expenses and also removed them from the cost of service in this proceeding. Staff's adjustments are identified on Schedule 9 of Staff's GMO Consolidated, MPS and L&P Accounting Schedules, Adjustments E-133.2.

Staff Expert/Witness: Michael Jason Taylor

3. Dues and Donations

Staff reviewed the list of membership dues paid and donations made to various organizations that GMO charged to its utility accounts during the test year. Staff removed costs for which it considers the expenses to be of a personal nature to a GMO employee or of no direct benefit to the ratepayers and, thus, should not be included in a utility's cost of service. Staff's adjustments are identified on Schedule 9 of Staff's GMO Consolidated, MPS and L&P Accounting Schedules, Adjustment E-114.3, E-146.4, E-159.2

GMO accounted for donations made to charitable organizations as a below-the-line expense amount-expenses that are not included in the determination of the revenue requirement. Staff examined, but did not find, any other donations that should be removed from the cost of service.

While Staff recognizes the importance of charitable contributions, donations such as these do not provide any direct benefit to ratepayers and are not necessary for the provision of safe and adequate service. In addition, recovery in rates of donations made by regulated utilities would constitute an involuntary contribution on behalf of the rate paying customer. For these reasons, utility rates typically do not include cost recovery of charitable donations.

a. Edison Electric Institute ("EEI") Dues

According to information obtained from the EEI website (www.eei.org), EEI is an association of investor-owned electric utilities and industrial affiliates. Based upon its review of EEI information, Staff determined that a primary function of EEI is to represent the interests of the electric utility industry in the legislative and regulatory arenas. This role includes EEI's engagement in lobbying activities.

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

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

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

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

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

GMO failed to quantify ratepayer and shareholder benefits from its participation in EEI; therefore, Staff removed all EEI dues included in the test year from GMO's cost of service.
Staff Expert/Witness: Michael Jason Taylor

4. Miscellaneous Test Year Adjustments

In its December 31, 2015 cost of service calculation, GMO computed Adjustment CS-11, which includes several categories of miscellaneous adjustments and amounts to a total GMO cost-of-service reduction of $2,133,391. The categories within the adjustment are summarized as:

a. Remove equity compensation from the test year;
b. Adjustment to test year resulting from officer expense report review;
c. Accounting code corrections;
d. Remove test year balances for GMO's L&P rate district's landfill costs.

Staff has reflected GMO's adjustments for equity compensation, expense reports, accounting code corrections, and landfill costs in Adjustments E-21.2, E-45.3, E-54.2, E-71.3, E-71.4, E-106.5, E-145.8, E-146.6, E-146.7, E-149.3, E-159.5, E-159.6 and E-185.1.
Staff Expert/Witness: Matthew R. Young

5. Expense Report Review

Staff reviewed KCPL employee expense reports to determine if any inappropriate, unreasonable or excessive charges were in the test year cost of service. Staff initiated this review in the context of the Management Audit of KCPL, ordered by the Commission in Case No. EO-2016-0124, and determined that certain expenses booked by the Company "above the line" and attempted to be charged to ratepayers should not be recovered in such a manner. Such expenses should instead be borne by shareholders. Further Staff examination of the expense account process will continue during the course of Staff's analysis in Case No. EO-2016-0124.

Staff's review revealed some categories of expense that Staff recommends should not be included in the cost of service. While some of these expenses were charged "below the line," others were charged "above the line" to accounts that are normally included in the cost of service. These expenses included the following:

- Royals Baseball Events
- Chiefs Football Events
- Concerts, etc.
- Other Employee Event Expenses

Staff's adjustments are identified on Schedule 9 of Staff's GMO consolidated, MPS and L&P Accounting Schedules, in various accounts.

Staff Expert/Witness: Keith Majors

6. <u>Debit/Credit Card Acceptance Program</u>

In September 2009, GMO implemented a Credit/Debit Card payment program designed to offer utility ratepayers a simplified, quick, convenient way to pay their bills, and to manage their accounts electronically. The program is offered by GMO in an agreement with Western Union through its SpeedPay service, which acts as a third party facilitator for the processing of payments to GMO. When payment is made by a customer through the credit or debit card system, GMO will receive payment from Western Union. Payment options available to customers through the program include the Interactive Voice Response System ("IVR") and/or online payments made by registering on GMO website. Payment through the website offers the following two options: (1) one-time payments, or (2) what the Company terms the "recurring card payment option," which is available through registration on its website. The cost for providing this service is absorbed by GMO and later built into rates; therefore, customers who use this payment option are not charged any direct transaction fees. Since the introduction of the program in September 2009, customer participation has been gradually increasing. Participation is projected to continue to increase into the future as more customers become aware of the program. As customer participation increases, the per-unit transaction cost to GMO for providing the debit/credit payment service will decline.

Staff included in its cost of service an annualized amount of expense associated with the credit and debit card program based upon the total card level and per-unit transaction cost as of the update period, the twelve-months ended December 31, 2015, to represent an ongoing level of costs (Adjustment No. E-126.5).

Staff Expert/Witness: Matthew R. Young

7. **Accounts Receivable Bank Fees**

Factoring accounts receivable results allows GMO to collect revenues on an accelerated basis from a lending institution. The adjustment for bank fees relates to the costs of selling the accounts receivable. The benefit to the company is that it receives enhancement to its cash flows. For rate-making purposes, the benefit of an accelerated cash collection process is in turn passed on to utility customers through reflection of a shorter revenue lag in the Cash Working Capital Accounting Schedule than otherwise would have occurred absent the sale of the accounts receivable.

When GMO filed its last rate case[83] in February 2012, it did not have an accounts receivable sales program in place. In that case, GMO witness John P. Weisensee stated on page 43, lines 13 and 14, of his direct testimony that GMO anticipated "entering into an accounts receivable sales facility similar to that in place for KCP&L prior to the August 31, 2012 true up." As expected, GMO entered into a Receivables Sale Agreement effective May 31, 2012, between GMO, GMO Receivables Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch, as agent, and Victory Receivables Corporation. Staff has examined the historical bank fees related to the factored accounts receivable and reflected an annualized expense, based on the time period of January 1, 2015, through December 31, 2015, in Adjustments E-128.3 and E-128.4.

Staff Expert/Witness: Matthew R. Young

8. **Lease Expense**

Lease costs are those costs incurred by KCPL, and allocated to GMO, for the leasing of its corporate headquarters. Staff examined these costs for the test year ended June 30, 2015, and update period through December 31, 2015.

Staff in its calculations recognized the monthly base rent for the headquarters, and multiplied that by 12 months to reflect an annualized rent amount. In addition to the lease rent amount, the Company pays other costs for customer and employee parking, as well as a rental fee in the agreement for additional space when needed. KCPL currently rents five classifications of parking spaces: Visitor, Reserved, High Profile Vehicles, Director and Unreserved. To calculate an annualized amount for parking, Staff obtained the number of spaces provided in

[83] Case No. ER-2012-0175.

each category, except for visitor parking which is based upon Company estimates, and multiplied the number of spaces by the monthly rate, then further multiplied that total by 12 months to derive an annual value. Staff also used the adjustments of the Company to remove amounts that were associated with other standard parking accounts (such as employee-subsidized parking), so as to avoid double-counting this expense. Once the applicable portions of the lease expense are totaled (base rent, parking, and additional rent) those amounts are then allocated between KCPL, GMO, and Great Plains. Staff's adjustments are identified on Schedule 9 of Staff's GMO consolidated, MPS and L&P Accounting Schedules, Adjustments E-146.2, E-147.2, E-160.1, E-165.2

Staff Expert/Witness: Michael Jason Taylor

9. Insurance Expense

Staff's recommended treatment of Insurance Expense is to treat insurance premium prepayments as an asset that is included in rate base and include an annualized level of insurance expense in rates. Prepayments are discussed in detail in the *Prepayments* section of this report. Insurance expense is the cost of protection obtained from third parties by utilities against the risk of financial loss associated with unanticipated events or occurrences. Utilities, like non-regulated entities, routinely incur insurance expense in order to minimize their liability associated with unanticipated losses for property assets and personal injury from accidents. Certain forms of insurance reduce the ratepayers' exposure to risk. Premiums for insurance are normally pre-paid by utilities; i.e., payment is made by the utility to the insurance vendor in advance of the policy going into effect.

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

- Crime
- Fiduciary Liability
- Directors and Officers
- General Liability/Umbrella
- Workman's Compensation
- Property
- Auto Liability
- Bonds

Staff reviewed the policies and verified the current insurance premiums for each insurance type. An annualized amount was determined for Great Plains, who obtains insurance policies for KCPL and GMO, and allocated to GMO for inclusion in the cost of service. The annualized levels for GMO's portion of the insurance costs are reflected in Adjustments E-149.4 and E-150.4.

Staff Expert/Witness: Matthew R. Young

10. Injuries and Damages

Staff's recommended treatment of injuries and damages is to normalize GMO's costs associated with injuries and damages, using a three-year average of actual cash payments made by GMO and paid to individuals who had an injury and claim. Injuries and damages relate to insurance claims that are not covered by insurance policies. Injuries and damages usually consist of claims associated with general liability, workman's compensation, and auto liability. Staff analyzed twelve years of data and determined that a three-year average, including the period of 2013 through 2015, of actual cash payments should be used to normalize GMO's costs associated with injuries and damages. A three-year average is appropriate because the annual expense was found to be fluctuating. This normalization of known and measurable cash payments is consistent with GMO's method to adjust injuries and damages in its rate case. Adjustment E-150.3.

Staff Expert/Witness: Matthew R. Young

11. Property Tax Expense

Staff's recommended treatment of property tax expense is to annualize tax expenses by multiplying the amount of plant GMO had in-service on January 1, 2016, by Staff's property tax ratio derived from GMO's 2015 tax payments.

Each year, GMO is billed for these taxes by each of the taxing authorities that have jurisdiction over GMO's property. Tax bills for the year are based (assessed) on the property GMO owns exclusively on January 1st of that calendar year. The property taxes assessed in Missouri on January 1 of each year are typically not due to the taxing authorities until December 31 of that same year, and in the state of Kansas, part of the year's property taxes are not due until late in the first quarter of the following year. The test year used in this case is the

12-month period ended June 30, 2015, updated through December 31, 2015. Since the update period in this case is December 31, 2015, Staff determined the annualized property taxes based on the property GMO had in-service on January 1, 2016. Staff applied a property tax ratio based on actual 2015 property tax payments to January 1, 2015 plant. This ratio of property taxes when applied to the January 1, 2016, plant provides the amount of property taxes expected to be paid for 2016. Both Staff and GMO typically perform this adjustment by looking to the tax rate paid for the previous year, and then applying it to the property owned at the start of the current year.

For the current rate case, Staff obtained from GMO the total amount of taxable property owned on January 1, 2016, and then applied the tax ratio experienced in 2015. The property tax ratio assessed in 2015 is calculated by dividing the total amount of property tax paid by GMO by the total cost of the taxable property owned by GMO on January 1, 2015. Any required payments in lieu of taxes ("PILOTs") applicable to non-taxable property were added to the total estimated tax for 2016. Staff recommends this method of calculation as providing the best available information, since it relies on the actual January 1, 2016, balance of GMO's property, and uses the most recent, known tax ratio (2015) without attempting to estimate any change in the rate of taxation for 2016 that is not known as of the update period December 31, 2015, and will not be known as of the true-up period July 31, 2016. Staff's methodology described above, reflected in Adjustment E-183.1 in Staff's GMO Consolidated Accounting Schedules, is consistent with GMO adjustment CS-126. Staff's approach is also consistent with the Staff's approach in prior cases. This approach has received several favorable rulings from the Commission, most recently in KCPL 2006 rate case. In its *Report and Order* issued in Case No. ER-2006-0314 the Commission stated the following:

> Staff recommends that the Commission calculate property tax expense by multiplying the January 1, 2006 plant-in-service balance by the ratio of the January 1, 2005 plant-in-balance to the amount of property taxes paid in 20015. KCPL wants the property tax cost of service updated to include 2006 assessments and levies. The Commission finds that the competent and substantial evidence supports Staff's position, and finds this issue in favor of Staff.

Staff Expert/Witness: Matthew R. Young

12. **Rate Case Expense**

Rate case expense is the sum of the costs a utility incurs in preparing and filing a rate case. In the instant case, GMO has incurred expenses in conjunction with legal counsel, regulatory consulting, and outside consultants. Staff recommends full recovery of rate case expense incurred to comply with statutory requirements; namely, the expenses for GMO's depreciation study. Staff recommends assigning the remaining discretionary rate case expense to both ratepayers and shareholders. The assignment of rate case expense to shareholders is based upon the ratio of Staff's recommended rate increase to GMO's requested rate increase. This ratio will be updated throughout the remainder of the case and will ultimately be based on the ratio of the Commission approved rate increase to GMO's requested rate increase.

a. Background

Generally, Staff divides rate case expense over the period of time it estimates will pass before the utility's next rate case and includes an annual amount in the utility's revenue requirement. Typically, this cost is not "amortized" for ratemaking purposes, and the utility's recovery of this expense in rates is not tracked against its actual rate case expense for consideration of over or under recovery.

However, regarding KCPL, that Company's Regulatory Plan contemplated four rate case filings over less than four years. Staff did not oppose the "defer and amortize" or "vintage accounting" approach that KCPL requested in each of the Regulatory Plan rate cases—Case Nos. ER-2006-0314, ER-2007-0291, ER-2009-0089 and ER-2010-0355. For the rate case expenses for each of these cases, as adjusted, Staff used a "defer and amortize" approach to calculate the associated revenue requirement to be included in the following rate case. Under this special "defer and amortize" approach to rate case expense, KCPL deferred the rate case expenses for each rate case as a separate vintage deferral and amortized each of those vintage deferrals over a multi-year period. The rate case expense KCPL incurred after the end of the true-up period in one case was deferred until the next rate case for consideration of recovery. When Great Plains acquired GMO in 2007, GMO's rate case expense was afforded identical "defer and amortize" treatment in Case Nos. ER-2009-0090 and ER-2010-0356.

In Case No. ER-2012-0175, Staff returned to its more typical normalization approach for establishing an ongoing level of rate case expense to include in GMO's revenue requirement because the Regulatory Plan rate cases were completed. However, an amortization, beginning on

June 25, 2011, of rate case expense incurred in the 2010 Rate Case was not completed until June, 2014. Therefore, the 2012 Rate Case included amounts in rates for the amortization of deferred rate case expenses arising from the 2010 Rate Case. In the current case, Staff has recognized the recovery of the final vintage of deferred and amortized rate case expense incurred in the 2010 Rate Case.

b. Recommendation

In addition to recognizing the end of the amortizations of deferred rate case expenses, Staff is recommending that the Commission approve the recovery of a portion of GMO's incurred costs, based upon the difference between the Commission approved rate increase and the Company's requested increase. Staff recommends that any subsequent over or under-recovery by GMO of the ordered amount should not be recognized in future cases.

Since rate case expense is typically end-loaded (i.e. a material amount of cost is incurred near the end of the case, i.e. evidentiary hearings), Staff's examination of rate case expense resulting from this case is not complete. Staff will continue to examine GMO's rate case expense in this case and will update total rate case expense until a cut-off point is determined.

Staff Adjustment E-156.2 reflects Staff's recommended rate case expense, calculated as described above. Staff Adjustment E-156.3 spreads the cost recovery of GMO's depreciation study over five years, the required time-interval for GMO to conduct depreciation studies. Staff Adjustment E-156.4 removes the 2010 Rate Case amortization from the test year.

c. Rate Case Expense Sharing Recommendation

Rate case expense can be defined as all incremental costs incurred by a utility directly related to an application to change its general rate levels. These applications are usually initiated by the utility, but rate case expenses may also be incurred as a result of the filing of an earnings complaint case by another party. The largest amounts of rate case expense usually consist of costs associated with use of outside witnesses, consultants and outside attorneys hired by the utility to participate in the rate case process.

Generally, utility management has a high degree of control over rate case expense. Attorneys, consultants and other services can either be provided by in-house personnel or can be procured from an outside party. Some Missouri utilities employ in-house counsel and primarily utilize internal labor to process rate filings; therefore, the use of outside attorneys in rate proceedings is not always necessary. However, GMO currently procures outside counsel in addition to several in-house attorneys with significant prior experience in Missouri rate proceedings. Rate case expenses generally do not include internal labor costs as those are included in the cost of service through the payroll annualization and are not incremental expenses resulting from the rate case process.

During rate proceedings, and generally in the utility regulatory process, there are four broad categories of costs involved:

1. The cost incurred by the Commission for itself and its Staff;
2. The cost incurred by the Public Counsel;
3. The cost incurred by intervenors in Commission proceedings; and
4. The cost incurred by the utility in the regulatory process.

Category 1 is the cost incurred by the Commission. This includes all operating expenses, salaries, wages, and benefits of the Commission and its Staff. The Commission's operating expenses are limited to the amount the Missouri General Assembly appropriates for that purpose. An annual amount of operating expenses are assessed by the Commission and paid by the utilities it regulates. The utility, in turn, passes on this expense to its ratepayers through the rate case process. The utility is not charged the direct cost of processing its filings or regulating company-specific activities. GMO is charged based on an assignment of the Commission's budget to regulation of the electric industry with this amount allocated to KCPL based on the percentage of GMO's regulated revenues of the total electric regulated revenues in Missouri.

Category 2 is the cost incurred by the Public Counsel. Public Counsel represents the public and interests of utility customers in proceedings before the Commission. An amount for Public Counsel's annual operating expenses is appropriated by the Missouri General Assembly which is sourced from the Commission's assessment.

Category 3 is the cost incurred by intervenors in Commission proceedings. Intervenors may be involved in Commission proceedings for a variety of reasons, but most frequently related to revenue requirement and rate design issues raised in general rate proceedings. Some intervening parties represent large individual utility customers or groups of customers. There are several intervenors in this case, some of whom have retained their own counsel and experts to review GMO's rate increase. Each intervenor is responsible for its own rate case expenses.

Category 4 is the cost incurred by the utility in the regulatory and rate setting process. The Commission has generally allowed utilities to pass through to ratepayers the full amount of normalized and prudently incurred rate case and regulatory expenses in the rate-setting process.

Of the four above-listed categories, the utility is the only party in the rate case process that does not face an inherent limit in the amount of rate case expense it can recover. The other three categories of rate case participants are limited in the amounts of rate case expense they can recover by the budgetary decisions of the General Assembly or by the willingness and ability of intervening parties to fund rate case activities. However, full rate case expense recovery means the utilities are able to plan their rate case activities without constraint because the cost of those activities will be passed on to the captive ratepayers.[84] This paradigm is inherently inequitable, both to the ratepayers and to the other participants in the rate case process.

Both ratepayers and shareholders benefit from the rate case process. Customers have a vested interest in ensuring that they pay just and reasonable rates for safe and adequate service and shareholders have a vested interest in ensuring an opportunity to receive a reasonable return on their investment. If the utility determines that the rates it charges its customers are inadequate, the ratemaking process before the Commission is the sole venue to remedy that situation. However, utility regulation in Missouri is, at least in part, premised upon an assumption that the utility is not likely in all circumstances to act in the best interests of its customers. This assumption points out the inequity of having customers finance a utility's efforts to obtain a rate increase that may ultimately be found by the Commission to be excessive or unreasonable in amount.

The practice of allowing a utility to recover all, or almost all, of its rate case expense from customers creates a disincentive for the utility to control rate case expenses. For all other parties to the rate case process, the funds spent are ultimately limited by a budget and financial restraints. Having significant financial resources to fund rate case activities combined with the ability to pass through the entire amount of the expenses creates what can be perceived as an unfair advantage over all other parties in the rate case process.

Some of a utility's discretionary expenses are traditionally disallowed in the ratemaking process, even if such expenditures are considered "prudent" from the perspective of the utility.

[84] "Captive" in that they have no say in the utility's decision to incur rate case expense and no ability to seek an alternative provider of utility services.

For example, charitable donations have historically not been an includable expense in the cost of service. Donations are defined as discretionary amounts paid to individuals or organizations for charitable reasons, with no direct business benefit. While the utility may believe it has a responsibility to be a "good corporate citizen," charitable contributions, if included in the cost of service, would equate to an involuntary contribution by the ratepayers. Costs associated with political activities ("lobbying") are another type of cost usually disallowed and not included in customer rates. These are costs that are unnecessary for the provision of safe and adequate utility service in Missouri.

On April 27, 2011, the Commission issued an Order establishing Case No. AW-2011-0330, and within this docket directed its Staff to investigate the Commission's current rules and practices regarding recovery of rate case expense in rates by Missouri utility companies. In particular, the Commission asked whether the current policy of generally allowing rate recovery of the entire amount of a utility's incurred rate case expense should be changed either by assigning some portion of these costs to the utility's shareholders, or instituting an overall "cap," or limit, on the amount of recovery of rate case expense in rates by utilities. The Commission stated its concern over rate case expense issues was related to testimony presented in recent rate cases and the recent escalation in the amount of claimed rate case expenses by Missouri utilities. As part of its investigation into these matters, Staff was directed to investigate the practices of other public utility commissions regarding rate recovery of rate case expense.

Several alternative approaches were discussed by Staff for the Commission's consideration in its Report in Case No. AW-2011-0330 that was filed in September 2013. One of the options for rate case expense recovery presented in Staff's Report was tying a utility's percentage recovery of rate case expense to the percentage of its rate increase request it is successfully awarded by the Commission.

Staff presented this sharing mechanism, along with other alternatives, in the Cost of Service report and testimony in Case No. ER-2014-0370, KCPL's most recent rate case. The Commission ordered a sharing of rate case expenses in its *Report and Order* in Case No. ER-2014-0370, on page 72:

> The Commission finds that in order to set just and reasonable rates under the facts in this case, the Commission will require KCPL shareholders to cover a portion of KCPL's rate case expense. One

> method to encourage KCPL to limit its rate case expenditures would be to link KCPL's percentage recovery of rate case expense to the percentage of its rate increase request the Commission finds just and reasonable. The Commission determines that this approach would directly link KCPL's recovery of rate case expense to both the reasonableness of its issue positions and the dollar value sought from customers in this rate case.
>
> The Commission concludes that KCPL should receive rate recovery of its rate case expenses in proportion to the amount of revenue requirement it is granted as a result of this Report and Order, compared to the amount of its revenue requirement rate increase originally requested. This amount should be normalized over three years. The Commission also finds that it is appropriate to require a full allocation to ratepayers of the expenses for KCPL's depreciation study, recovered over five years, because this study is required under Commission rules to be conducted every five years. [footnotes omitted]

In accordance with the Commission's *Report and Order*, Staff recommends the same rate case expense sharing with regard to GMO's rate case expense.

Staff concludes that this sharing of expenses is appropriate in this proceeding for the following reasons:

1. This sharing mechanism was ordered by the Commission in the recent KCPL rate case, Case No. ER-2014-0370;
2. Rate case expense sharing creates an incentive, and eliminates a disincentive, on the utility's part to control rate case expense to reasonable levels;
3. Considering that ratepayers currently pay for the majority of the rate case and regulatory process, it is fair and equitable to ask shareholders to pay for at least some of these expenses;
4. Both ratepayers and shareholders benefit from the rate case process; the ratepayer receiving safe and adequate service at a just and reasonable rate, and the shareholder receiving an opportunity to receive an adequate return on investment.

Staff intends to examine sharing options for rate case expense in future general rate proceedings for major utilities, and may advocate a different approach to sharing, or different sharing percentages, depending upon the circumstances of each individual filing.

Staff Expert/Witness: Matthew R. Young

13. <u>Regulatory Assessments</u>

a. Public Service Commission Assessment Fee

The Public Service Commission assessment ("PSC Assessment") is an amount billed to all regulated utilities operating under the jurisdiction of the Commission as an allocation of the Commission's operating costs associated with utility regulation. GMO's PSC Assessment was annualized using the latest assessment available for the current fiscal year (FY-2017) on information obtained from the Commission's records. The updated GMO PSC Assessment was compared to the PSC Assessment amount included in GMO's test year to form the basis for the adjustment in Staff's cost-of-service run. Staff witness Karen Lyons addresses the separate FERC Assessment adjustment below. Staff's adjustments are identified on Schedule 9 of Staff's GMO Consolidated, MPS and L&P Accounting Schedules, Adjustment E-155.1.

Staff Expert/Witness: Michael Jason Taylor

b. FERC Assessment

GMO is also assessed a regulatory fee from FERC. The FERC assesses fees to public utilities and Regional Transmission Organizations ("RTO") based on their usage of transmission of electric energy. Staff reviewed GMO's FERC assessment for the period of January 2012 through December 2015. Beginning in June 2013, GMO incurred FERC assessment costs from the MISO RTO. Based on discussions with GMO personnel, for the period of June 2013 through December 2013, GMO incurred a FERC assessment only for purchased power from MISO. For the period of January 2014 through December 2015, GMO personnel confirmed that the FERC assessment it incurred from MISO was directly related to the Crossroads generating facility located within the MISO territory. During the January 2014 to December 2015 timeframe, GMO did not enter into any purchased power agreement in MISO.

The Commission stated in its *Report and Order* in Case No. ER-2010-0356, "it is not just and reasonable to require ratepayers to pay for the added transmission costs of electricity generated so far away in a transmission constricted location."[85] The Commission further stated in its *Report and Order* in Case No. ER-2012-0175, "the Crossroads transmission costs does *[sic]* not support safe and adequate service at just and reasonable rates, and the Commission will

[85] Case No ER-2010-0356 Report and Order, paragraph 247, May 4, 2011.

deny those costs."[86] Since the Commission disallowed Crossroads transmission costs in Case No. ER-2010-0356, and Case No. ER-2012-0175, Staff made an adjustment to also eliminate the FERC Assessment fees incurred by GMO for its MISO transmission for the 12-month period ending December 31, 2015, that is associated with Crossroads. Staff's adjustment to eliminate FERC assessments related to Crossroads is identified on Schedule 9 of Staff's GMO consolidated, MPS, and L&P Accounting Schedules, Adjustment E-152.3.

Staff did, however, include an annualized level of the FERC assessment incurred by GMO for its SPP RTO transmission based on the 12-month period ending December 31, 2015. Staff's adjustment is identified on Schedule 9 of Staff's GMO consolidated, MPS, and L&P Accounting Schedules, Adjustment E-152.2.

Staff Expert/Witness: Karen Lyons

14. Customer Deposits – Interest Expense

Staff's recommended treatment of interest expense on customer deposits is to include the interest expense in the expense portion of the revenue requirement calculation, since customer deposits were deducted in the calculation of rate base. Staff recommends that the appropriate amount of interest expense is the Staff's calculated amount of interest expense that GMO should have paid its customers for interest on their customer deposits. Staff calculated the interest for customer deposits consistent with the level of customer deposits reflected in the Rate Base – Schedule 2 (see discussion in the Rate Base section of this report for Customer Deposits included in rate base). GMO's tariff states that the "interest on deposits shall be paid at a per annum rate equal to the prime bank lending rate plus one percentage point as published in The Wall Street Journal for the first business day of December of the preceding calendar year, compounded annually" (Sheet 1.09, Paragraph 2.07(D)(2), Tariff Effective September 1, 2009). For this calculation, Staff used the method outlined in the Company's tariff which is to use the customer deposit balance to be included in rate base, and then multiply that number by the most current prime interest rate published in the Wall Street Journal (3.50%) plus 1%, for a total of 4.50%. GMO had used an interest rate of 4.25% (3.25% prime rate plus 1%) for its computation of interest expense from customer deposits for the test year, and recorded this expense on its income statement. For ease of computation and since most residential customers' deposits are

[86] Case No ER-2012-0175 Report and Order, Page 59, January 9, 2013.

refunded to customers after 12 consecutive satisfactory monthly payments, only simple interest is considered for the interest expense calculation even though the tariff calls for compounded interest. GMO's booked interest expense related to customer deposits is also treated similarly. The amount of interest related to customer deposits has been included as an adjustment to the Income Statement – Schedule 9 in Staff's GMO Consolidated Accounting Schedules, Adjustment E-126.2. The Commission should base its awarded revenue requirement on Staff's recommended amount of interest related to customer deposits by including the customer deposit interest expense amount calculated by Staff as an expense adjustment to GMO's income statement.

Staff Expert/Witness: Sean M. Cahoon

15. <u>Depreciation - Clearing</u>

During the test year, GMO included depreciation for transportation equipment that was charged to expense through a clearing account. Staff made an adjustment to remove the depreciation amount booked to the clearing account. Staff's adjustment is identified on Schedule 9 of Staff's GMO consolidated, MPS and L&P Accounting Schedules, Adjustment E-158.1.

Staff Expert/Witness: Karen Lyons

16. <u>Economic Relief Pilot Program</u>

The Economic Relief Pilot Program (ERPP or "Program") was established in Case No. ER-2009-0090, to help relieve the financial hardship experienced by some GMO customers. The current program is open to income-eligible customers, defined as an annual household with an income no greater than 185 percent of the Federal Poverty Level ("FPL"), which is used to determine eligibility for certain programs and benefits.

The ERPP provides up to 1,000 participants with a fixed credit on their monthly bill for a period of up to 12 months from the billing cycle, designated by the Company as the participant's first month, until the billing cycle designated as the participant's last for ERPP. At the end of the twelve-month period, a customer may reapply to participate further in the program through the term of the pilot program.

The program currently has an annual funding level of $630,000, $315,000 from shareholders and $315,000 from ratepayers. The program delivers up to $50 dollars per month "fixed credit" to income eligible customers to help improve energy affordability. At this time the program falls short of the 1,000 monthly participant cap by an average of about 10% each month.

GMO is proposing to continue the ERPP and to increase the annual ratepayer funding from $315,000 to $394,010 and annual shareholder funding from $315,000 to $394,010 for a total annual program funding of $788,019. According to the current tariff, if "any program funds in excess of actual program expenses remain at the end of the ERPP program, the Company shall redirect the excess funds to tariffed demand-side management programs." The Company is proposing a change to this by making the excess funds available for the future ERPP expenditures in the next program year.

At this time GMO is proposing to leave the number of participants the program benefits each month at the current level of up to 1,000, but based on monthly ERPP data reports submitted to Staff, the participant level cap of 1,000 per month is not being met. The Company is also proposing an increase in the available monthly credit to each participant from $50 to $65 as well as proposing to change the availability limits for the program to 200% of the federal poverty level, up from the current 185%.

Staff is awaiting information from a data request on the number of customers allowed to participate per month and on the impact this program has had on late payments and arrearages. Based on information received from the data request, Staff may later make a recommendation in regards to proposed raise of the monthly customer cap.

This program was originally approved in Case No. ER 2009-0009,[87] as a 3-year pilot program, and in Case No. ER-2012-0175,[88] it was recommended in Staff Witness Contessa Poole-King's Surrebuttal Testimony that there be an additional 3-year pilot period to ensure ERPP was a viable program before its pilot status was changed. This recommendation was given after Staff on August 23, 2012, had the opportunity to review evaluation results from True North Market Insights, LLC, GMO's third-party program evaluator. Staff's position at that time was that, "Staff feels the customer survey results contained in the evaluation are insufficient.

[87] Case No. ER-2009-0009, *In the Matter of the Application of KCP&L Great Missouri Operations Company for Approval to Make Certain Changes in it Charges for Electric Service.*
[88] Rebuttal testimony of Staff Expert Witness Contessa Poole-King, Case No. ER-2012-0175, *In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement General Rate Increase for Electric Service.*

The methodology used to assess customer feedback of the program was isolated to 10% of currently enrolled ERPP participants. The random sampling approach should have included customers that were removed from the program by GMO, customers that requested removal from the program, and those that successfully completed the program. A random sampling of all program participants would provide a comprehensive assessment of the program." There has not been a more recent third-party evaluation of the program since the evaluation submitted in 2012.

At this time, Staff has three recommendations. First, Staff is supportive of continuing the ERPP program. Staff recognizes the benefit of the monthly "fixed-credit" to relieve some financial hardship experienced by low-income customers. Additionally, the program is beneficial because it targets low-income customers that may not qualify for other assistance programs due to income eligibility requirements.

Second, Staff recommends the approval of the funding level increase by GMO's proposed total program fund amount from $630,000 annually to $788,019 annually, continuing with the current program funding terms of 50% ratepayer funded and 50% shareholder funded. Additionally Staff recommends allowing the Company to increase the monthly credit up from $50 to up to $65 and increasing the FPL from 185% to 200%.

Third, Staff recommends an evaluation of the program be performed with a sampling of survey participants higher than 10% of active participants and the inclusion of prior participants so as to get a better objective evaluation.

Staff Expert/Witness: Kory Boustead

a. Accounting Treatment

Staff's recommended treatment of the ERPP is to include the costs, at the amount discussed above by Staff Witness Kory Boustead, as an ongoing level of expense. To include ERPP funding from ratepayers, Staff examined the expenses booked in the test year and made an adjustment to increase the test year ERPP expense to the amount recommended to be recovered in rates.

The Commission originally ordered the funding of this program through base rates in GMO's Case No. ER-2012-0175. Beginning with the effective date of rates in that case, Staff calculated the amount of funds that GMO collected from ratepayers and matched by shareholders, which was earmarked for ERPP, and compared the total funding to GMO's ERPP expenditures over that same time frame. The results show that GMO has a balance of approximately $141,000 of unspent ERPP funding as of December 31, 2015. Staff recommends that the under-spent amount, along with future unspent amounts, be made available for future ERPP-related activities.

In addition to collecting ERPP funding through base rates, GMO has been recovering the cost of two vintages of ERPP deferred costs. Vintage 1 represents ERPP costs incurred between Case Nos. ER-2009-0090 and ER-2010-0356, which were included in base rates resulting from Case No. ER-2010-0356, as an amortization expense. Vintage 2 represents ERPP costs incurred between Case Nos. ER-2010-0356 and ER-2012-0175, which were included in base rates resulting from Case No. ER-2012-0175, as an amortization expense. The first vintage of costs was amortized over a three year period and fully recovered in May 2014 while the second vintage, with the same amortization period, was fully recovered in January 2016. The following table shows the amounts collected from ratepayers related to expired ERPP amortizations at various dates throughout this case:

	MPS		L&P		Total
Excess Amortization @	Vintage 1	Vintage 2	Vintage 1	Vintage 2	GMO
December 31, 2015	$95,357	$0	$32,263	$0	$127,620
July 31, 2016	$132,033	$13,112	$44,671	$6,918	$196,734
December 31, 2016	$158,230	$24,038	$53,535	12,682	$248,486

Since the cost recovery was built into base rates as part of the order in Case No. ER-2012-0175, and rates have not been reset to date, GMO continues and will continue, to collect revenue for ERPP costs that have been fully recovered through current base rates. Staff recommends that the excess revenue collected from ratepayers for these ERPP amortizations be matched by shareholder funds and be made available for future ERPP-related activities. For the purposes of setting rates in this case Staff made an adjustment to remove test year amortization expense in Adjustment E-133.6. Staff will re-perform a comparison of monies earmarked for ERPP with actual ERPP costs in GMO's next rate case.

Staff Expert/Witness: Matthew R. Young

17. <u>Income Eligible Weatherization Program (formally Low Income Weatherization Program)</u>

The funding for GMO's Income-Eligible Weatherization Program ("Weatherization Program"), (formerly Low-Income Weatherization Program) was authorized as an expense to be included in rates in the Commission's *Report and Order* ("Order") in GMO's rate case, Case No. ER-2010-0356.[89] In its Missouri Energy Efficiency Incentive Act ("MEEIA") filing, Case No. EO-2012-0009,[90] GMO requested that the Commission approve the low-income weatherization program as a MEEIA program, and the Commission approved GMO's request on November 15, 2012, in the *Order Approving Non-Unanimous Stipulation and Agreement Resolving KCP&L Greater Missouri Operations Company's MEEIA Filing.* The Company's MEEIA Cycle 1 programs went into effect on January 26, 2013, and programs for GMO's MEEIA Cycle 2 (Case No. EO-2015-0241[91]) went into effect April 1, 2016. GMO's Income-Eligible Weatherization Program is currently in MEEIA Cycle 2 Program Year 1, but will transition out of GMO's MEEIA Cycle 2 on March 31, 2017, but will be recovered under base-rates resulting from the current rate case, Case No. ER-2016-0156. The Commission ordered the income-eligible weatherization program to be removed from KCPL MEEIA rider in KCPL's most recent rate case (Case No. ER-2014-0370), Therefore, Staff recommended the Company remove the program from GMO's MEEIA rider because the program is an important service that benefits low-income residents and the need to ensure the continuity of the program going forward. To avoid any continuity problems in the future collecting program funds through base rates is preferable over recovery of this program through the GMO MEEIA rider.

Low-income consumers often live in housing that is energy inefficient with substandard insulation and other deficiencies. These customers would benefit from building-shell energy conservation measures such as weatherization or energy efficient appliances. GMO and its customers benefit from the low-income weatherization program through the reduction in the

[89] ER-2010-0356, *In the Matter of the Application of Kansas City Power & Light Company for Approval to Make Certain Changes in it Charges for Electric Service to Continue the Implementation of it Regulatory Plan*, issued April 12, 2011, effective Date April 22, 2011, pp. 175-182. The Order in Case No. ER-2010-0355 (KCPL) was inclusive of Case No. ER-2010-0356 (GMO).

[90] EO-2012-0009, *In the Matter of KCP&L Greater Missouri Operations Company's Filing for Approval of Demand-Side Programs and for Authority to Establish a Demand-Side Programs Investment Mechanism.*

[91] EO-2015-0241, *In the Matter of KCP&L Greater Missouri Operations Company's Filing for Approval of Demand-Side Programs and for Authority to Establish a Demand-Side Programs Investment Mechanism.*

expenses associated with arrearages in billing and shutoffs, which occur in greater proportions among low-income customers.

The Missouri Low-Income Weatherization Assistance Program ("Weatherization Program"), which is federally, state, and utility funded, is administered by the Missouri Department of Economic Development, Division of Energy ("DED-DE"). The Missouri Weatherization Program is administered locally by Community Action Agencies or other local agencies ("Weatherization Agencies"). The GMO Weatherization Program provides funds for weatherization of GMO's low-income customers' homes in its service area. For the GMO Weatherization Program, the Company administers funds at the local level for weatherization of its qualified low-income customers which is performed by the United Services Community Action Agency ("USCAA"), the West Central Missouri Community Action Agency ("WCMCAA"), the Missouri Valley Community Action Agency ("MVCAA"), the Community Services, Inc. of Northwest Missouri, Maryville ("CSI"), and Community Action Partnership of Greater St. Joseph ("CAPSTJO").

At this time, Staff recommends continuation of GMO's Income-Eligible Weatherization program in permanent rates for this case at an annual revenue requirement of $300,000, reflected in Staff Adjustment E-133.7. Staff also recommends GMO work closely with the Weatherization Agencies to address any process barriers, and to find resolutions to overcome them, so the Company's program funds can be spent within the program year as timely as possible.

Staff Experts/Witnesses: Kory Boustead

18. <u>Regional Transmission Organization Administrative Fees</u>

The SPP is a not-for-profit, regional transmission organization ("RTO") that maintains functional control over the transmission assets of its members and provides transmission services through its FERC approved Open Access Transmission Tariff ("Open Access Tariff" or "OATT"). SPP's costs must be recovered from its users (transmission customers, which, in this case, are utility companies such as KCPL, GMO, The Empire District Electric Company, Westar Energy, Inc. and many others). Consequently, GMO pays SPP an administration charge for performing transmission functions on its behalf.

Under its Open Access Tariff, SPP establishes a rate for its administration charge annually that enables it to recover 100% of its total annual administrative costs for RTO functions, subject to a rate cap. The rate cap serves as a limit on the annual administration charge in order to provide SPP customers a level of certainty and predictability regarding SPP's year-to-year administrative costs. SPP's administrative rate cap is currently $.39 per MWh and in 2015, SPP members paid administrative fees based on the $.39 per MWh cap. Although the administrative fee rate cap is still in effect, on December 8, 2015, SPP's Board of Directors approved SPP's Finance Committee recommendation to reduce the administrative fee to $.37 per MWh. The following chart reflects SPP's historical administrative fee rate for the period of 2006-2016.

Historical SPP Administrative Fee per Mwh											
Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Rate	$.16	$.19	$.19	$.17	$.195	$.210	$.255	$.315	$.381	$.39	$.37

Staff annualized SPP administration fees based on the administrative rate of $0.37 per MWh effective January 1, 2016, and included an annualized amount for the North American Electric Reliability Corporation ("NERC") fees. Staff also made an adjustment to eliminate Midwest Independent Transmission System Operator ("MISO") RTO administrative fees for point to point transmission. The Commission's Orders in both Case No. ER-2010-0356 and Case No. ER-2012-0175 prohibited GMO from any recovery of transmission costs for Crossroads.[92] Prior to December 19, 2013, when Entergy became a member of MISO, Entergy billed GMO for firm point-to-point transmission expense for Crossroads. Subsequent to Entergy becoming a member of MISO in December 2013, MISO billed GMO for transmission administrative fees directly related to Crossroads in addition to firm point to point transmission. Since the Commission has previously prohibited GMO from any recovery of transmission costs, Staff made an adjustment to eliminate the MISO transmission administrative fees.

[92] Case No. ER-2010-0356, Commission Report and Order, Page 99. Case No. ER-2012-0175, Commission Report and Order, Page 59.

Staff's adjustments for SPP Administration fees and the elimination of MISO administrative fees are identified on Schedule 9 of Staff's GMO consolidated, MPS and L&P Accounting Schedules, Adjustments E-78.2, E-78.3, E-93.1 and E-93.2.

Staff Expert/Witness: Karen Lyons

19. <u>Transmission Expense-FERC Account 565</u>

KCPL and GMO are members of the SPP. In 2004, SPP became a regional transmission operator ("RTO") responsible for ensuring reliable supplies of power, adequate transmission infrastructure, and competitive wholesale electricity prices.[93] Prior to 2009, GMO had full functional control over its transmission system that served its retail customers within its service territory. In Case No. EO-2009-0179, GMO filed an application with the Commission to transfer functional control of its transmission facilities to SPP. The parties to this case entered into a *Stipulation and Agreement* on January 27, 2009, and the Commission approved the *Stipulation and Agreement* by Order effective on February 10, 2009. The transfer of functional control of GMO's transmission system to SPP was finalized upon the approval by the FERC on April 15, 2009.

As a transmission customer of SPP, SPP charges GMO for point-to-point, base plan zonal and region-wide transmission costs that are booked to FERC Account 565. Point-to-point transmission costs are billed based on Schedule 7 and Schedule 8 of SPP's Open Access tariff. Base-plan-zonal charges and region-wide charges are billed based on Schedule 11 of the Open Access tariff.

Base-plan-zonal and region-wide costs are a result of transmission upgrades in the SPP region. The transmission upgrades are directed by SPP's Transmission Expansion Plan in place to ensure the reliability of the transmission system for SPP's members.[94] The costs of base-plan and region-wide projects are allocated to the SPP region based on the voltage of the project. The allocation method is referred to as the Highway-Byway method and is shown in the following table:

[93] Market Protocols for SPP Integrated Marketplace, p. 60.
[94] SPP OATT Tariff.

SPP Base Plan Highway-Byway Allocation Method		
Voltage	Regional (SPP region)	Zonal (KCPL local zone)
300 kV and Above	100%	0%
100-300 kV	33%	67%
Below 100%	0%	100%

The costs allocated to the SPP region are then allocated to SPP transmission customers based on a load ratio share determination. The load ratio share is developed using the transmission customer's network load divided by the SPP total load. KCPL's current load ratio share, on a total company basis (Missouri and Kansas), is 7.35%. GMO's current load ratio share is 4.12%.

In addition to being charged by SPP for transmission expense, GMO is also charged by the Midwest Independent Transmission System Operator ("MISO") for Crossroads transmission expense. Since Crossroads is located in Mississippi, GMO contracts firm point-to-point transmission service with Entergy Service, Inc. ("Entergy"), to transport electricity from Mississippi to GMO's load center. On December 19, 2013, Entergy became a member of MISO. Consequently, GMO is now billed by MISO for the firm point-to-point transmission in addition to other MISO-related transmission charges. The MISO schedules currently applicable to transmission service directly associated with Crossroads are:

- Schedule 1 – Scheduling, System Control and Dispatch Service
- Schedule 2 – Reactive Supply and Voltage Control
- Schedule 7 – Long-term Firm Point-to-point Service
- Schedule 10 – ISO Cost Recovery Adder
- Schedule 10 FERC – Annual Charges Recovery
- Schedule 11 – Wholesale Distribution Service
- Schedule 26 – Network Upgrade from Transmission Expansion Plan
- Schedule 33 – Blackstart Service
- Schedule 45 – Cost Recovery of NERC Recommendation or Essential Action

All the schedules listed above are booked to GMO's transmission FERC account 565, with the exception of Schedule 10. Schedule 10 is MISO administrative and FERC fees and are addressed in the section of this report titled, *Regional Transmission Administrative Fees.*

The following chart compares GMO's annual historical and Crossroads transmission expenses to GMO's annual historical and Crossroads generation output, in mega-watt hours ("MWh"), for the period of 2009-2015. GMO's annual transmission expense was derived by combining MPS and L&P rate districts actual transmission expense booked in FERC account 565 and GMO's MWhs by combining MPS and L&P rate districts MWhs from its production report:

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As can be seen from the table above, Crossroads transmission expense represents ** ____ ** of GMO's total transmission expense in 2014 and 2015 and the MWhs generated by Crossroads represents less than ** __ ** of GMO's total MWh's of generation for the same years.

For the period of 2012-2015, GMO's transmission expenses have significantly increased. Consequently, Staff included an annualized level of total transmission expense based on the 12-month period ended December 31, 2015. Staff's adjustment for transmission expense is identified on Schedule 9 of Staff's GMO Consolidated, MPS and L&P Accounting Schedules, Adjustment E-82.1. The Commission's *Report and Orders* in both Case No. ER-2010-0356 and Case No. ER-2012-0175 prohibited GMO from any recovery through its retail rates of its Crossroads transmission costs.[95] Consistent with the Commission's *Report and Orders* in those cases, Staff eliminated GMO's Crossroads transmission expense for the 12-month period ending December 31, 2015. Staff's adjustment to eliminate Crossroads transmission expense in FERC account 565 is identified on Schedule 9 of Staff's GMO Consolidated, MPS and L&P Accounting Schedules, Adjustment E-82.2. Crossroads transmission expense is also discussed in the following Sections of this report: *Crossroads Energy Center, Regional Transmission Administrative Fees, and FERC Assessment.* Staff will review transmission expense in its True-Up audit based on updated events and cost information.

Staff Expert/Witness: Karen Lyons

20. Transition Costs

a. Aquila, Inc. Acquisition Amortized Transition Costs

Pursuant to the Commission's *Report and Order* in Case No. ER-2010-0356, GMO began amortizing deferred Aquila acquisition transition costs with the effective date of rates in that case on June 25, 2011. These transition costs were deferred pursuant to the Commission's *Report and Order* in Case No. EM-2007-0374. These deferred transition costs include non-executive severance costs for employees terminated, facilities integration costs, and incremental third-party and other non-labor expenses incurred as a result of the acquisition of Aquila, Inc. the predecessor of GMO.

Staff and GMO were Signatories to the *Non-Unanimous Stipulation and Agreement as to Certain Issues* in File No. ER-2012-0175. KCPL-GMO Common Issues - Issue II.7, was resolved on page 5 pursuant to the following terms:

> The five-year amortization of acquisition transition costs (KCPL annual amount of $3.8 million, GMO amount of $4.3 million—MPS $3.5 million and L&P $0.8 million) shall continue; however, KCPL and GMO shall not seek recovery of acquisition transition costs in any general electric rate case filed after January 1, 2015.

[95] Case No. ER-2010-0356, Commission *Report and Order*, Page 99. Case No. ER-2012-0175, Commission Report and Order, Page 59.

> Total Missouri jurisdictional transition costs related to the 2008 acquisition of Aquila are capped at the December 31, 2010 amount of $41.5 million. No other transition costs related to the 2008 acquisition of Aquila will be deferred for recovery in any general electric rate case.

GMO filed File No. ER-2016-0156 on February 23, 2016. This date is subsequent to January 1, 2015, the date past which GMO agreed to not seek recovery of amortized transition costs. In addition, the five year amortization ends May 2016. Therefore, Staff removed the test year amortized transition costs. Staff's adjustments are identified on Schedule 9 of Staff's GMO consolidated, MPS and L&P Accounting Schedules, Adjustments E-145.3 and E-148.1.

Staff Expert/Witness: Keith Majors

b. SJLP Transition Cost

Aquila, Inc., predecessor to GMO, acquired the St. Joseph Light & Power Company properties pursuant to the Commission's Report and Order in Case No. EM-2000-292. Aquila was authorized to defer and amortize transition costs pursuant to the Order Approving Stipulation and Agreement in Case No. ER-2005-0436. Transition costs in the amount of $4,959,664 were amortized to GMO-MPS and GMO-L&P over 10 years beginning on March 1, 2006, the effective date of rates in ER-2005-0436. The amortization ended February 2016.

GMO filed File No. ER-2016-0156 on February 23, 2016. The true-up date in this case, July 31, 2016, will capture costs past this end of amortization of transition costs date; therefore, Staff removed the test year amortized transition costs.

Staff's adjustments are identified on Schedule 9 of Staff's GMO consolidated, MPS and L&P Accounting Schedules, Adjustments E-145.2 and E-151.2.

Staff Expert/Witness: Keith Majors

21. <u>Demand-Side Management Cost Recovery</u>

Staff recommends that the Commission order the continuation of the current GMO demand-side management ("DSM") regulatory asset account mechanism[96] in conjunction with

[96] As established in ER-2009-0090, all DSM programs' costs will be placed in a regulatory asset account and receive interest at the AFUDC rate. In subsequent general electric rate proceedings, prudent DSM programs' costs incurred prior to December 31, 2010, will be amortized over a ten (10) year period. As established in ER-2010-0356, prudent

this rate increase request to allow full recovery of direct pre-MEEIA program costs. Prior to the implementation of MEEIA, GMO tracked and deferred costs incurred from DSM programs and established vintages containing DSM costs in between rate increases.

On June 10, 2009, the Commission issued its *Order Approving Non-Unanimous Stipulation and Agreements and Authorizing Tariff Filing* in Case No. ER-2009-0090 which approved the following:

> The Signatories agree that for ratemaking purposes GMO will defer the costs of its DSM programs in a regulatory asset, and annually calculate AFUDC on the balance in that regulatory asset. DSM programs are defined as demand response and energy efficiency programs. The prudently-incurred costs included in the regulatory asset balance will be amortized over a ten (10) year period. When new rates go into effect reflecting amortization recovery as a result of future general rate proceedings, the prudently-incurred costs included in the regulatory asset balance will be added to rate base, GMO will stop accruing AFUDC on the amount included in rate base, and GMO will begin amortizing the balance. Additional DSM program costs incurred after the effective date of a final Report and Order in GMO's next general electric rate proceeding following this case, Case No. ER-2009-0090, will be treated in the same manner, but will be deferred in a different sub-account by vintage.

The Commission's *Report and Order* in GMO's next rate case, File No. ER-2010-0356 directed that "DSM program costs for investments made from December 31, 2010, until a future recovery mechanism is in place shall be placed in a regulatory asset account and amortized over six years with a carrying cost equal to the AFUDC rate applied to the unamortized balance." In the same *Report and Order,* the Commission determined that "the unamortized balances of the regulatory asset account shall be included in rate base for determining rates in this case."[97]

Therefore, Staff recommends that the Commission order the continuation of the current GMO DSM regulatory asset account mechanism.

DSM programs' costs incurred on or after December 31, 2010, will be amortized over a six (6) year period and the unamortized balances will be included in rate base for determining rates in the case.

[97] Commission's *Report and Order* in File No. ER-2010-0356 issued on May 4, 2011, at pages 119 – 120.

a. Accounting Treatment for Expiring Vintages

While reviewing the amortization schedules for each vintage, Staff noted that Vintages 1 and 3 will be fully amortized within three years of the conclusion of the current rate case. Once the vintages are fully amortized, GMO will be collecting funds through rates for expenses it is no longer incurring. Staff recommends that once an amortization of a vintage is complete, GMO apply the funds that it will continue to collect for the fully amortized vintage to the unrecovered amount of the next-ending DSM vintage.

Staff Expert/Witness: Matthew R. Young

22. Amortization of Regulatory Liabilities & Assets

Staff recommends the Commission order a four-year amortization of the over-recovery in rates of deferrals resulting from an accounting authority order ("AAO") related to the 2007 L&P Ice Storm; and a four-year amortization of the over-recovery of the L&P Rate Phase-In from the amortized revenue to the L&P rate district's cost of service.

A utility must seek authority from the Commission to deviate from the accounting prescribed by the Uniform System of Accounts ("USOA"). Grants of authority to deviate from the USOA are commonly known as AAOs. Generally, AAOs enable a utility to delay booking an expense from the period in which it was incurred; instead booking that expense, or an amortized portion of it, in a period used to calculate its cost of service in a future rate proceeding.

In 2007, the city of St Joseph, Missouri, was struck by a significant ice storm. St. Joseph, Missouri, is within the GMO L&P rate district. The Company filed an application with the Commission for an AAO in Case No. EU-2008-0233, to defer the incremental maintenance and operational costs resulting from the ice storm. The Commission granted the AAO and ordered a five-year amortization of the costs with the amortization ending in 2013.

The January 9, 2013, Commission *Report and Order* in Case No. ER-2012-0175, approved a *Non-Unanimous Stipulation and Agreement as to Certain Issues* filed October 19, 2012, including the following provision:

> GMO's recovery of its five-year amortization for the L&P Ice Storm in December 2007 shall end on October 1, 2013, and to the extent GMO's L&P rate district rates from this case continue beyond that date, GMO shall "track" as a single issue the over-recovery of that amortization and adjust its revenue requirement

> for L&P in the following general electric rate case to return that "over-recovery" to its retail customers in its L&P rate district.

Consistent with the *Stipulation and Agreement* and Commission's *Report and Order*, GMO tracked the over collection of the ice storm amortization and included an annual amortization of the over recovery in its cost of service. Staff recommends an annual amortization of the over collection amount through July 2016, the true-up period in this case, based on a four-year period, be included in GMO's consolidated cost of service. Staff is currently recommending a four-year amortization to coincide with the expectation of the timing of GMO's next general rate case. Staff's adjustment is reflected in Staff's GMO consolidated and L&P Accounting Schedule 9, Adjustment E-171.1.

In Case Nos. ER-2010-0356 and ER-2012-0024, the parties reached an agreement to allow the L&P rate district to recover ordered revenue through a "phase-in." In Case No. ER-2012-0174, the previous agreement for a revenue phase-in was terminated. The parties reached a new agreement which established a three-year amortization to allow L&P recovery of the still unrecovered revenues, including carrying costs. The Commission approved the amortization on January 9, 2013, as part of the October 19, 2012, *Non-Unanimous Stipulation and Agreement as to Certain Issues*. The agreement for the amortization states:

> The phase-in of the rate increase in the L&P rate district that was the subject of Case Nos. ER-2012-0024 and ER-2010-0356 shall be terminated early and the unrecovered portion of the remaining increase plus carrying costs the Commission ordered be recovered shall be included in the revenue requirement for the L&P rate district in this case at the annual amount of $1,870,245. The annual amount of $1,870,245 is based on a three-year amortization of the unrecovered portion of the remaining increase plus carrying costs. **To the extent that GMO's general rates that include this annual amount for more than three years, GMO shall pro rate the annual amount by the time period beyond three years and shall reduce the revenue requirement upon which it bases its subsequent general electric rate increase to return that amount to its retail customers in its L&P rate district. [Emphasis added]**

The three-year amortization period ended in January 2016. Since the amortization is included in base rates, revenues will continue to be collected until the effective date of new rates in this case. Consistent with the agreement reached in Case No. ER-2012-0175, Staff recommends an annual amortization of the over-collection amount through July 2016, the true-up period in this case, based on a four-year period. Staff made an adjustment to include an annual amortization based on the revenue collected from the customers of the L&P rate district. Staff's adjustment is reflected in Staff's GMO consolidated and L&P Accounting Schedule 9, Adjustment Rev-3.1.

In addition to the amortizations discussed above, GMO amortizes several regulatory assets on its books and records. The Commission authorized these regulatory assets throughout several rate cases. A regulatory asset represents an amount that a utility is to recover from its customers through rates by amortizing the asset amount over an appropriate number of years and then including the annual amortization amount in the utility's cost of service. There are several amortizations that have expired or will expire by the anticipated effective date of rates in this case. Staff witness Matthew R. Young discusses Staff's treatment of expiring amortizations for GMO's Demand-Side Management ("DSM"), Economic Relief Pilot Program ("ERPP") and Renewable Energy Standards ("RES") in this report. The table below shows the remaining over-recovery of regulatory assets previously authorized by the Commission as of the true-up period and the anticipated effective date of rates in this case:

	Amortization End Date	GMO	MPS	L&P
SJLP Transition costs				
Amortization End Date	February 2016			
Annual Amortization		$495,967	$376,935	$119,302
Excess Amortization July 31, 2016		**$206,653**	**$157,056**	**$49,597**
Excess Amortization December 31, 2016		$413,306	$314,112	$99,193
Rate Case Expense-Case No. ER-2010-0356				
Amortization End Date	June 2014			
Annual Amortization		$950,067	$582,584	$367,483
Excess Amortization July 31, 2016		$1,995,139	$1,223,426	$771,713
Excess Amortization December 31, 2016		$2,391,000	$1,466,169	$924,831
Rate Case Expense-Case No. ER-2010-0356				
Amortization End Date	January 2016			
Annual Amortization		$86,734	$86,734	
Excess Amortization July 31, 2016		$43,367	$43,367	
Excess Amortization December 31, 2016		$79,506	$79,506	

Staff recommends that the over-recovery of the amortizations identified above as of the true-up period in this case be returned to GMO's ratepayers over a four-year period. Staff's adjustment to reflect a four-year amortization can be located in Staff's GMO consolidated, MPS and L&P Accounting Schedule 9, Adjustments E-144.6 and E-153.9.

Staff Expert/Witness: Karen Lyons

23. Allconnect Revenues and Expenses

Pursuant to the Commission's *Report and Order* in File No. EC-2015-0309, Staff has included an adjustment to restore the revenues and expenses related to the Allconnect Direct Transfer Service Agreement. The Commission ordered all expenses and revenues associated with the Allconnect relationship to be brought "above the line" and included in regulated cost of service, on page 22 of the *Report and Order* in that case:

> The Commission finds and concludes that the revenue and expense associated with the Allconnect relationship should be treated as regulated revenue and expense and brought "above the line." While the services Allconnect offers are not regulated by this Commission, KCP&L and GMO's relationship with its customers is regulated. Further, the customer information and contacts that KCP&L and GMO are selling to Allconnect are developed through that regulated relationship. Finally, moving the revenue and expenses above the line reduces the impression that KCP&L and GMO are selling their customer's information to increase their unregulated profits.

There are no expenses or revenues related to Allconnect in GMO's test year ending June 30, 2014. Therefore, Staff has included a full year of GMO's allocated share of Allconnect revenues and expenses through December 31, 2015. These adjustments are included in Staff's Accounting Schedule 9.

Staff Expert/Witness: Keith Majors

24. Common Use Plant Billings

Common use plant billings are the monthly billings to affiliated entities of KCPL and GMO for the entities' use of the companies' plant. Common use plant is plant on the books of

KCPL and GMO that can be used by affiliates of KCPL. KCPL and GMO charge for the use of these assets.

Included in the charge for common use plant is the impact of any capital additions amount KCPL and/or GMO has expended. A substantial amount of capital additions associated with network systems and software were added to the common use plant billing process during the test year. An adjustment is necessary to annualize the amount of common use billings. In KCPL's most recent case, Case No. ER-2014-0370, this adjustment was negative, as KCPL is a net allocator of common plant; that is, more common plant use is billed from KCPL than is billed to KCPL from its affiliates. In this case, GMO is a net user of common plant; that is, more common plant use is billed to GMO than is billed from GMO to its affiliates.

Staff's adjustments are identified on Schedule 9 of Staff's GMO consolidated, MPS and L&P Accounting Schedules, Adjustment E-147.3.

Staff Expert/Witness: Keith Majors

25. Corporate Allocations – Corporate Massachusetts Formula to General Allocator

During the test year, KCPL and GMO implemented a change in corporate cost allocation methodology beginning January 2015. File No. EO-2014-0189 is KCPL's Cost Allocation Manual docket. As a result of discussion with Staff in that docket, KCPL and GMO have changed the allocation methodology of residual common charges that are not directly assignable. Indirect costs formerly allocated using the Corporate Massachusetts Formula are now allocated using a General Allocator. An adjustment to expense is necessary for costs from July through December 2014 as these costs were allocated under the formerly used Corporate Massachusetts Formula.

Staff's adjustments are identified on Schedule 9 of Staff's GMO consolidated, MPS and L&P Accounting Schedules, in various accounts.

Staff Expert/Witness: Keith Majors

26. Transource Adjustments

GMO has included in its direct revenue requirement filing three adjustments related to the *Stipulation and Agreement* reached by the parties and included in the Commission's *Report* *and Order* in File No. EA-2013-0098 ("Transource Missouri Case"). The adjustments include the Transource payment to GMO for transmission assets, adjustments for the difference between Transource FERC revenue requirement and GMO FERC revenue requirement, and an adjustment to return costs booked in the test year of File No. ER-2012-0175 to GMO customers. For each of the adjustments described below, Staff reviewed GMO's MPS and L&P rate districts books and records and consolidated the adjustments to include in Staff's GMO Consolidated Accounting Schedules.

The first adjustment addresses transmission assets that were previously included in GMO's rate base. On page 28, Appendix 4, of the Commission *Report and Order* in File No EA-2013-0098 the Commission stated,

> Transource Missouri will pay GMO the higher of $5.9 million or net book value for transferred transmission assets, easements, and right-of-ways that have been previously included in the rate base and reflected in the retail rates of KCP&L and GMO customers. KCP&L and GMO agree to book a regulatory liability reflecting the value of this payment to the extent it exceeds net book value. This regulatory liability shall be amortized over three years beginning with the effective date of new rates in KCP&L's and GMO's next retail rate cases.

Through discussions with GMO personnel and review of GMO's adjustment, Staff confirmed the adjustment is consistent with the Commission approved *Stipulation and Agreement* in File No. EA-2013-0098. Staff's adjustment for the annual amortization of the Transource Missouri payment for transmission assets is identified on Schedule 9 of Staff's GMO Consolidated Accounting Schedules, Adjustment E-169.1.

The second adjustment addresses Transource Missouri FERC authorized rate treatments and incentives. On page 28, Appendix 4, of the Commission *Report and Order* in File No EA-2013-0098 the Commission stated,

> With respect to transmission facilities located in GMO certificated territory that are constructed by Transource Missouri that are part of the Iatan-Nashua and Sibley-Nebraska City Projects, GMO agrees that for ratemaking purposes in Missouri the costs allocated to GMO by SPP will be adjusted by an amount equal to the difference between: (a) the SPP load ratio share of the annual revenue requirement for such facilities that would have resulted if GMO's authorized ROE and capital structure had been applied and there had been no CWIP (if applicable) or other FERC Transmission Rate

> Incentives, including but not limited to Abandoned Plant Recovery, recovery on a current basis instead of capitalizing pre-commercial operations expenses and accelerated depreciation, applied to such facilities; and (b) the SPP load ratio share of the annual FERC-authorized revenue requirement for such facilities. GMO will make this adjustment in all rate cases so long as these transmission facilities are in service.

Transource Missouri Annual Transmission Revenue Requirement ("ATTR") reflects costs, such as CWIP, that are not allowed to be recovered in retail rates in Missouri. In addition, Transource Missouri's FERC authorized return on equity is 50 to 100 basis points higher than GMO's FERC authorized return on equity. GMO performed an analysis to determine the differences between FERC and GMO ratemaking for the projects at issue in File No. EA-2013-0098 in order to comply with the Commission's *Report and Order* language quoted above. Staff reviewed GMO's proposed adjustment and recommends it be revised in various respects to make it consistent with the Commission's *Report and Order* in File No. EA-2013-0098.

Staff's proposed changes are as follows:

- Depreciation rates – depreciation rate differences between the Missouri and FERC jurisdictions do not result from FERC Transmission Rate Incentives, and therefore should not be included in the difference calculation
- State income tax rates – differences in assumed state income tax rates do not result from FERC Transmission Rate Incentives, and therefore should not included in the difference calculation
- Cost of debt – differences in the assumed cost of long term debt do not result from FERC Transmission Rate Incentives, and therefore should not be included in the difference calculation
- Allowance for Funds Used During Construction ("AFUDC") – this amount, representing the capitalized financing cost for the projects, was adjusted to reflect GMO and KCPL's actual AFUDC rates over time

Staff's adjustment for the difference of costs allocated to GMO by SPP that includes Transource Missouri FERC incentives and the costs based on GMO's FERC authorized return on equity is identified on Schedule 9 of Staff's GMO Consolidated Accounting Schedules, Adjustment E-82.3.

The third adjustment reflects costs that should have been charged to Transource Missouri but were retained on the regulated books of GMO's MPS and L&P rate districts for the test year period in File No. ER-2012-0175, 12 months ending September 2011. GMO is proposing a regulatory liability with an amortization period of 3 years for these costs. GMO Witness Ron Klote states on page 54 of his direct testimony:

> This regulatory liability is the result of a review of all Transource related charges from project creation in August of 2010 to August of 2013. The review consisted of the following four areas:
>
> - Labor – Labor charges of all the project participants were reviewed.
> - Non-Labor – All invoices were reviewed for the vendors who supported the Transource project.
> - Expense Reports – Expense reports of the Transource project participants were reviewed.
> - Facilities Allocation – A portion of common facilities was allocated to the Transource project.

Through discussions with GMO personnel and review of GMO's adjustment, Staff confirmed the adjustment is consistent with the Commission approved *Stipulation and Agreement* in File No. EA-2013-0098. Staff's adjustment for the annual amortization of these costs is identified on Schedule 9 of Staff's GMO Consolidated Accounting Schedules, Adjustments E-145.4, E-148.2 and E-160.2.

Staff Experts/Witnesses: Karen Lyons and Keith Majors

IX. Depreciation

A. Plant-In-Service Review

Staff visited the Lake Road and Iatan facilities on Wednesday, May 18, 2016. Staff reviewed items from the Continuing Property Record provided by GMO in its response to Staff Data Request No. 0099 and chose the top ten plant dollar items for each operating unit for the Lake Road and Iatan plants; Staff verified 191 units of property (assets) that totaled approximately $605 million and represented about 17.2% of the Company's plant dollars as of

December 31, 2015. The South Harper, Ralph Green, Greenwood, and Sibley plants were visited the following day, and Staff verified 147 units of property that totaled approximately $295 million, representing about 8.4% of the Company's plant dollars as of December 31, 2015. Collectively for the two days, Staff verified 338 units of property valued at approximately $900 million, representing 25.6% of the Company's plant dollars as of December 31, 2015. Many of these items were large dollar assets (units) and consisted of Boilers, Turbines, Burner Assemblies, Control Panels, Wire Raceways, and similar items.

B. Stopped Depreciation Issue identified in ER-2012-0175

In GMO's prior two rate cases, Staff identified two issues concerning GMO's depreciation accruals that occurred prior to its acquisition by Great Plains. The first was the premature halting of depreciation accruals, and the second was the use of Aquila's corporate depreciation rates to book accruals, which were different than the Missouri authorized rates.

Staff first became aware of GMO's premature halting of depreciation accruals for plant still in service in Case No. ER-2009-0090. The resulting understatement of reserves was identified in GMO's response to Staff Data Request No. 0247 in that case as $3,942,866, and was updated in former Staff witness Rosella Shad's Surrebuttal Testimony and the Staff's Cost-of-Service Report as $4,221,178. This issue was addressed in the Non-Unanimous Stipulation and Agreement as to Certain Issues in Case Number ER-2012-0175 (GMO's previous rate case), page 6, Depreciation Issues (EFIS Item 259 in the docket). It was agreed that the Company would make an adjustment of $4,221,178 for stopped depreciation.

Staff verified that the Company has made the agreed to adjustment. The Company made the necessary journal entries and provided the journal entry adjustments in their response to Staff Data Request No. 0264.

C. Staff's Review of GMO's Submitted Depreciation Study

Staff reviewed the 2014 Depreciation Studies provided by the Company's consultant, Gannett Fleming Valuation and Rate Consultants, LLC. ("Gannett Fleming"). GMO provided four separate depreciation studies—one for GMO, one for GMO's MPS rate district, one for GMO's L&P rate district, and one for ECORP. Staff reviewed the historical retirement, cost of removal and salvage data files, and conducted a depreciation analysis using Staff's version of the

Gannett Fleming depreciation software. The table below compares the plant in service balances, book reserves, future accruals and the annual accrual amounts for each respective district.

Depreciation Study by District	Plant in Service as of 12-31-2014	Book Reserves	Future Accruals	Annual Accruals
L&P	$ 710,740,530.45	$ 285,559,351.00	$ 574,110,574.00	$ 23,096,087.00
MPS	$ 2,253,601,381.88	$ 902,744,380.00	$ 1,912,673,460.00	$ 69,388,303.00
ECORP	$ 388,057,794.51	$ 47,001,681.00	$ 380,750,104.00	$ 10,799,700.00
Total	$ 3,352,399,706.84	$ 1,235,305,412.00	$ 2,867,534,138.00	$ 103,284,090.00
Combined Study	$ 3,352,399,706.38	$ 1,235,305,412.00	$ 2,947,595,550.00	$ 100,943,913.00
Combined/Total	100.0%	100.0%	102.8%	97.7%

The separate depreciation studies only include plant in service that is allocated to each respective rate district (L&P, MPS, and ECORP). The combined depreciation study includes all plant in service for all three districts aggregated together. The Company is recommending the annual accrual amounts (and thus depreciation rates) be used from their combined study, which is a $2.34 million reduction versus separate districts.

D. Staff Recommendations Depreciation Rates

This rate case will ultimately require Staff to true-up rates through July 31, 2016. At the beginning of Staff's analysis of depreciation accrual rates, the plant in service balances through December 31, 2015, were available. Staff's review of the Company's requested depreciation rates indicates concerns related to several of the Company's electric generation units: Sibley Units 1 and 2 and Lake Road Unit 4. The Company's study used a projected retirement date at Sibley Units 1 and 2 of 2019 and Lake Road Unit 4 used a retirement date of 2020. Staff's further evaluation of these units has raised concerns. These concerns are summarized as follows:

- For Account 312.00 Boiler Plant Equipment – company booked a $6,017,687 (33%) reduction in booked reserves between December 31, 2014, and December 31, 2015, for Sibley Unit 1. For Sibley Unit 2, Staff found similar percentage reductions.
- For Production Plant, the Company's net salvage percentage is set as high as 25% of original plant cost. To determine if the net salvage percentages are appropriate, a determination of the apportionment of total plant that is related to cost of removal should be made.
- In response to data requests, Staff was given the reserve and plant balances, plant additions, retirements, and salvage transactions. However, Staff could not derive the reserve balances that the company has booked. Staff is still investigating the general ledger entries to demonstrate the calculation of reserve balances for all accounts.
- The "Probable Retirement Dates" in the company's Depreciation Study indicates Sibley Units 1 and 2 retiring in year 2019 and Lake Road Unit 4 in year 2020. Other document sources such as the Company's Integrated Resource Plan indicates that Sibley Units 1 and 2 no longer produce power after year 2018 and Lake Road 4 after 2019. Since the rates are determined based on remaining life, a reasonable estimate of the actual retirement dates of these units need clarification to provide the most accurate depreciation accrual rates for these facilities.

Staff currently is investigating the above items to arrive at a set of depreciation rates that are amenable to all parties to this case. Staff hopes to alleviate these concerns through technical conferences, additional data requests, and conference calls with the Company and other interested parties.

Until Staff's concerns are alleviated, for its direct revenue requirement calculation, Staff used the depreciation rates shown in Appendix 3, Schedule DAM-d1, for all of GMO's plant accounts, which are the current Commission ordered depreciation rates from the ER-2012-0175 case.

E. Staff Recommendation

Staff's recommends the Commission order the depreciation rates for GMO's electric operations presented in Appendix 3, Schedule DAM-d1.

Staff Expert/Witness: Derick A. Miles, PE

F. Income Statement – Depreciation Expense

Staff witness Derick Miles is recommending depreciation rates for Total GMO Combined and separately for GMO's MPS and L&P rate districts. These recommended depreciation rates were included in Accounting Schedule 5—Depreciation Expense. Accounting Schedule 5 identifies the adjusted Missouri jurisdictional plant balances from Accounting Schedule 3-Plant in Service, and then applies the recommended depreciation rates to determine the jurisdictional level of depreciation expense which is included in Accounting Schedule 9—Income Statement.

Staff Expert/Witness: Cary G. Featherstone

X. Current and Deferred Income Tax

A. Current Income Tax

Current income tax for this case has been calculated by Staff generally consistent with the methodology used in KCPL's last rate case, Case No. ER-2014-0370. A tax timing difference occurs when the timing used in reflecting a cost (or revenue) for financial reporting purposes is different from the timing required by the Internal Revenue Service ("IRS") in determining taxable income.

Current income tax reflects timing differences consistent with the timing required by the tax regulations. The tax timing differences used in calculating taxable income for computing current income tax for GMO are as follows:

Add Back to Operating Income Before Taxes:

Book Depreciation Expense

Plant Amortization Expense

50% Meals and Entertainment IRS Disallowance

Subtractions from Operating Income Before Taxes:

Interest Expense (Weighted Cost of Debt x Rate Base)

IRS Accelerated Tax Depreciation

IRS Tax Return Plant Amortization

Staff's income taxes are calculated on Staff's Accounting Schedule 11.

Staff Expert/Witness: Keith Majors

B. Elimination of Corporate Franchise Taxes

Prior to 2016, Missouri corporations were required to pay a franchise tax based on the par value of the corporation's outstanding shares and surplus. The Missouri franchise tax was fully phased out effective January 1, 2016; therefore, the test year per book amounts have been removed from the cost of service.

Staff's adjustments are identified on Schedule 9 of Staff's GMO consolidated, MPS and L&P Accounting Schedules, Adjustment E-186.1.

Staff Expert/Witness: Keith Majors

C. Deferred Income Taxes - Crossroads

Pursuant to the Commission's *Report and Order* in Case No. ER-2012-0174, Staff has reduced the amount of deferred taxes related to the Crossroads combustion turbines. The net amount of deferred taxes is based on the Commission ordered value of Crossroads. This value, and the associated adjustments to GMO's books and records, are further discussed by Staff witness Cary G. Featherstone in this report. The reduction to deferred taxes is in Staff's Accounting Schedule 2 – Rate Base.

Staff Expert/Witness: Keith Majors

D. Deferred Income Tax Expense

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

Staff's deferred income taxes are calculated on Staff's Accounting Schedule 11.

Staff Expert/Witness: Keith Majors

E. Accumulated Deferred Income Taxes ("ADIT")

GMO's deferred income tax reserve represents, in effect, a prepayment of income taxes by GMO's customers to the Company prior to payment being made by the Company to taxing authorities. As an example, because GMO is allowed to deduct depreciation expense on an accelerated basis for income tax purposes, depreciation expense used for income taxes is significantly higher than depreciation expense used for financial reporting (book purposes) and for ratemaking purposes. This results in what is referred to as book-tax timing difference. This timing difference creates a deferral of liability for income taxes to the future. The net credit balance in the deferred tax reserve represents a source of cost-free capital to GMO. Therefore, GMO's rate base is reduced by the deferred tax reserve balance to avoid having customers pay a return on funds that are provided cost-free to the company. Generally, deferred income taxes associated with all book-tax timing differences which are created through the ratemaking process should be reflected in rate base. Besides accelerated depreciation, Staff has also included deferred taxes specifically associated with the rate base inclusion of the pension liability and other tax timing differences.

The rate base impact of ADIT is included in Schedule 2 – Rate Base in Staff's accounting schedules.

Timing differences which were reflected as a tax deduction in the current year, for current income tax to the IRS, were deferred (normalized) for ratemaking purposes. The tax deduction is reflected in rates by amortizing the deferred tax balance over the depreciable life of the property. Staff's income tax calculation for GMO, in this current case, reflects the amortization of prior timing differences which were normalized in prior rate cases.

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

Prior to the 1986 Tax Reform Act, a utility received a permanent tax credit for investing in new capital additions. For ratemaking purposes, the IRS allowed the utility to amortize (flow back to ratepayers) the investment tax credit over the approximate depreciable book life of the related property.

Staff Expert/Witness: Keith Majors

F. ADIT on Construction Work In Progress ("CWIP")

GMO records ADIT associated with the CWIP that is reflected on its books and records. This ADIT represents a free source of capital funds available for use by the utility before the construction project is completed and included in plant-in-service. CWIP is excluded from the rate base on which GMO earns a return in the ratemaking process. Although CWIP is not included in rate base, GMO is allowed to earn an Allowance for Funds Used During Construction ("AFUDC") before the property under construction is added to rate base. AFUDC is accrued during the construction of the asset and included in rate base when the plant is placed into service. The amount of AFUDC is included in rate base and in the amount of depreciation expense recorded for the asset over the life of the plant. For the calculation of AFUDC, there is no consideration for ADIT as a reduction to the base on which it is calculated; the AFUDC is calculated on the "gross" amount, with no consideration of ADIT as a source of cost-free capital.

Utilities have argued that it is inappropriate to reduce rate base for ADIT associated with CWIP balances, when the CWIP amounts are not included in rate base. However, the Commission has found to the contrary recently. Reducing rate base by the amount of ADIT on CWIP was an issue decided by the Commission in the recent Ameren Missouri general rate case, Case No. ER-2012-0166. On page 30 of its *Report and Order* in that case, the Commission stated why this treatment is appropriate:

> In other words, failure to recognize the CWIP-related ADIT balance in the company's rate base will overstate the companies AFUDC costs and future rate base, essentially allowing the company to earn AFUDC and a return on capital supplied by ratepayers...
>
> ...As fully explained in the findings of fact, Ameren Missouri must include CWIP-related ADIT balances as an offset to rate base to

> avoid overstating AFUDC and future rate base, to the detriment of both current and future ratepayers.

On page 79 of its *Report and Order* in Case No. ER-2014-0370, the Commission affirmed its treatment of ADIT on CWIP on page 79:

> KCPL asserts that its situation is different than that of the utility at issue in File No. ER-2012-0166 because KCPL has a net operating loss and, as a consequence, KCPL has more deductions than it has revenues during the applicable period, so it has not and will not receive a cash tax benefit. However, KCPL ratepayers provide fully-normalized income taxes in cost of service regardless of whether KCPL pays those taxes concurrently to the IRS. Even if KCPL is not realizing all the benefits of accelerated depreciation due to a net operating loss position, it does not invalidate the fact that ratepayers are providing several million dollars in cash income taxes. The Commission concludes that the amount of ADIT related to CWIP should be an additional reduction to KCPL's rate base.

The amount of ADIT on CWIP is included as a reduction to rate base on Schedule 2 – Rate Base, in Staff's accounting schedules, as part of the balance of deferred taxes.

Staff Expert/Witness: Keith Majors

XI. Jurisdictional Allocations

Jurisdictional allocation factors are used to allocate demand-related and energy-related costs to the applicable jurisdictions. Fixed costs, such as the capital costs associated with generation and transmission plant, are typically allocated on the basis of demand. Variable costs, such as fuel, are more appropriately allocated on the basis of energy consumption. Demand-related and energy-related costs are divided among two jurisdictions: wholesale operations and retail operations. The particular allocation factor applied is dependent upon the type of cost that is being allocated.

Although Staff is recommending the consolidation of GMO's MPS and L&P rate districts into one GMO company-wide entity, Staff also developed separate jurisdictional allocators for GMO's MPS and L&P rate districts, if applicable, which were used in the associated attached accounting schedules for the individual rate districts.

Staff Expert/Witness: Alan J. Bax

A. Methodology

1. Demand Allocation Factor

Demand refers to the rate at which electric energy is delivered to a system to match the requirements of its customers ("load"), generally expressed in kilowatts ("kWs") or megawatts ("MWs"), either at an instant in time or averaged over a specified time interval. System peak demand is the largest electric load requirement that occurs within a specified period of time, (e.g. hour, day, month, season or year) on a utility's system. Since generation units and transmission lines are planned, designed, and constructed to meet a utility's anticipated system peak demands, plus required reserves, the contribution of each of the applicable jurisdictions: wholesale operations and retail operations, coincident to the system peak demand, i.e., each jurisdiction's demand at the time of the corresponding system peak, is the appropriate basis on which to allocate the costs of these facilities. Thus, the term coincident peak ("CP") refers to the load in the respective jurisdictions that coincide with the applicable overall system peak recorded for the time period considered in the particular analysis.

In general, a utility that experiences similar hourly peaks in both winter and summer seasons should utilize a 12 CP methodology. A utility that experiences monthly peaks during the summer months should utilize a 4 CP method. A utility experiencing a needle peak in a particular month may necessitate using a 1 CP method.

GMO's MPS rate district has historically experienced peaks during the four summer months. Therefore, its demand allocation factors should be calculated utilizing a 4 CP method. MPS serves five municipal electric systems. Thus, both retail and wholesale factors will need to be developed for the MPS rate district.

However, GMO's L&P rate district has historically experienced peaks both in the winter and in the summer months. As a result, a 12 CP method is more appropriate to use in its analysis. However, GMO's L&P rate district has not served any municipal or other public electric system. Therefore, it is not necessary to calculate demand and energy allocation factors for GMO's L&P rate district.

When evaluating the load information for GMO on a company-wide basis, a 4 CP methodology will be used in calculating corresponding jurisdictional allocation factors for both wholesale and retail operations for the greater GMO system. The monthly demands reported for the calendar months included in the test year and update period for the current case are consistent with the monthly demands in the reporting periods associated with the last few rate cases involving GMO and its aforementioned rate districts.

Staff determined the applicable demand allocation factors for GMO on a company-wide basis and separately for GMO's MPS rate district,[98] using the following process:

a. Identify the overall system's hourly peak load in each month in calendar year 2015 and sum the hourly peak loads.
b. Sum the particular jurisdiction's corresponding loads for the hours identified in a. above.
c. Divide b. by a. above.

Staff's calculated demand allocation factors for both retail and wholesale operations of GMO on a company-wide basis using the 4 CP method are as follows:

Retail Operations:	0.9964
Wholesale Operations:	0.0036

2. Energy Allocation Factor

The energy allocation factor for an individual jurisdiction is the ratio of the normalized annual kilowatt-hour ("kWh") usage in the particular jurisdiction to the total normalized GMO kWh usage, with adjustments for losses and anticipated growth as well as annualization adjustments.

Staff calculated energy allocation factors for the retail and wholesale jurisdictions for both GMO on a company-wide basis and separately for GMO's MPS rate district.[99] The applicable jurisdictional allocation factors for GMO on a company-wide basis are:

Retail Operations:	0.9962
Wholesale Operations:	0.0038

[98]The results of Staff's calculations for GMO's MPS rate district, applying a 4 CP methodology, are:

Retail Operations:	0.9954
Wholesale Operations:	0.0046

A similar calculation is not applicable to the L&P rate district.

[99]The results of Staff's calculations for GMO's MPS rate district are:

Retail Operations:	0.9950
Wholesale Operations:	0.0050

A similar calculation is not applicable to GMO's L&P rate district.

These jurisdictional allocation factors will be used by Staff witness Cary G. Featherstone in Staff's EMS run used to allocate related demand and energy expenses and revenues to the Missouri retail jurisdiction.

Staff Expert/Witness: Alan J. Bax

B. Application

In order to develop the cost of service runs for the GMO combined case and GMO's MPS rate district, the allocation factors discussed above were applied to the various FERC accounts for plant (accounting Schedule 3), reserve (Accounting Schedule 6) and the income statement (Accounting Schedule 9). Since GMO's L&P rate district does not have any wholesale customers, it does not have to allocate costs to the FERC jurisdiction.

As stated above, GMO's MPS rate district operates within Missouri and in the wholesale jurisdiction regulated by the FERC. It is necessary to identify, then allocate and/or assign, specific investments and costs among these two jurisdictions (Missouri Retail and Wholesale). To identify the combined GMO and the separate MPS' revenue requirement, Staff must develop the consolidated cost of service and the stand-alone MPS' cost of service for its Missouri retail jurisdiction. To do that, the GMO combined and GMO's MPS plant investments in rate base and costs in the income statement must be appropriately assigned or allocated to the Missouri retail jurisdiction.

To develop GMO combined and GMO's MPS cost of service for its Missouri retail jurisdiction, Staff began with GMO's MPS records kept in accordance with FERC accounting requirements per Commission rule. Where these records reflected costs or investments that GMO's MPS rate district incurred solely to serve the Missouri retail jurisdiction, Staff directly assigned those costs or investments to GMO's MPS Missouri jurisdictional cost of service. However, when it was not appropriate to directly assign costs or investments, Staff allocated those costs using either a demand or energy allocation factor, depending upon whether the investment or cost was incurred more due to demand or more due to energy.

GMO combined and GMO's MPS stand-alone uses its generation and transmission facilities to produce and transport electricity to its Missouri retail customers and wholesale customers (FERC jurisdiction). Because they are operated in scale with demand, Staff allocated the GMO combined and GMO's MPS costs and investments in these facilities, as well as the related depreciation reserve accounts, to the state and federal jurisdiction on the basis of demand, i.e., with demand allocators. Since GMO combined and GMO's MPS rate district is a four summer month peaking utility, Staff used the 4 CP method to develop the Missouri retail jurisdiction and wholesale jurisdiction demand allocators. Staff has consistently used the 4 CP method to develop the GMO MPS demand allocators over several GMO rate cases.

In its records kept in accordance with FERC accounting requirements, GMO accounts for its investment in distribution plant located in Missouri. Plant identified in this way is referred to as site specific or *situs* plant. Consistent with how GMO MPS treated distribution plant in its case, Staff used GMO combined and GMO's MPS actual distribution plant investment in Missouri at December 31, 2015, to develop site specific allocation factors to allocate the total company distribution plant and reserve amounts to quantify only the distribution plant and reserve amounts specific to GMO combined and GMO MPS Missouri retail jurisdiction.

Using the principle that expenses (costs) should follow plant investment, Staff used the same jurisdictional allocation factors it developed to allocate investment to allocate expenses related to that investment. The FERC expense accounts found in GMO combined and GMO's MPS income statement (reproduced as Schedule 9 in Staff's Accounting Schedules) include amounts for costs broadly described as production, transmission, distribution, and administrative and general ("A&G"). Using the expense accounts found in GMO combined and GMO's MPS income statement, this principle that expenses should follow plant investment is appropriate because the Company incurs production (generation) plant expenses to maintain and operate the generating facilities making it proper to use the same jurisdictional allocator to allocate production plant expense that is used to allocate its generating facilities investment. Similarly, costs are incurred for transmission expenses to maintain and operate its transmission facilities making it appropriate to use the same jurisdictional allocator to allocate transmission expenses that are used to allocate investment in its transmission facilities.

Staff allocated the production and transmission costs taken from the income statements to Missouri retail jurisdiction with the same demand allocator Staff developed and used to allocate investment in generating and transmission facilities to the Missouri retail jurisdiction.

Staff created the Missouri retail jurisdictional allocation factor for general plant investment, and related costs, based on a composite of the demand allocation factor applied to generation and transmission assets and the site specific allocation factor for distribution assets.

Staff applied the demand allocation factor used to quantify the Missouri jurisdictional share of the production and transmission costs and the site specific allocation factor used to allocate an appropriate part of total company distribution plant and reserve amounts to the Missouri retail jurisdiction for GMO combined and GMO MPS. Staff used the resulting production and transmission plant and depreciation reserve amounts and distribution plant costs allocated to Missouri retail jurisdiction to form the basis for allocating general plant to its Missouri retail jurisdiction. Thus, Staff's Missouri retail jurisdiction allocation factor for general plant is based on a composite of the Missouri retail jurisdiction allocation factors Staff developed for MPS' production, transmission and distribution plant costs. Staff used this composite general plant allocation factor to allocate to GMO's MPS Missouri retail jurisdiction what are described in GMO's MPS income statement (Staff's Accounting Schedule 9) as "general" costs.

GMO's L&P rate district has only Missouri retail jurisdiction so all its operations are 100% Missouri. However, GMO's L&P rate district does have industrial steam operations with plant investment and costs that must be allocated between the electric and steam operations. Staff witness Charles Poston addresses the allocation factors relating to the steam operations.

Staff also used a variety of jurisdictional allocation factors to allocate the appropriate part of GMO's MPS and GMO's L&P rate districts' administrative and general costs found in all the cost of service runs for GMO combined, and GMO's MPS and L&P income statements (Accounting Schedule 9), to the Missouri retail jurisdiction. Staff relied on GMO for these allocation factors. Some of these allocation factors are based on the number of GMO customers in each jurisdiction. Some are based on the number of KCPL employees working in each KCPL and GMO jurisdiction. Each specific account had a specific allocation factor that Staff used to allocate the appropriate cost to GMO's MPS and GMO's L&P Missouri retail jurisdiction.

Staff used the energy allocation factor to allocate costs to the Missouri retail jurisdiction that are considered to vary directly with electricity usage. For example, in response to increased demand for electricity, GMO must either buy or generate more electricity causing one or more of its fuel and purchased power costs to increase—there is a direct relationship in the level of megawatts generated or purchased and the amount of fuel and purchased power costs. In contrast, costs such as fixed capacity, or demand charges are constant regardless of the demand for electricity and, therefore, are allocated using the demand allocator.

The rationale for the demand component of a capacity purchase or sale is to recover the fixed costs of the facilities that underlie these transactions. For example, if GMO sells capacity, it makes a commitment to have generating capacity in place that is dedicated to meeting the load requirements of the customer to whom it is selling the capacity. This is similar to GMO's requirement to have fixed capacity available to meet the load requirements of its residential, commercial and industrial customers (referred to as its "native load" customers) at every point in time. The demand component of a capacity sale can be thought of as a rate of return on, and of, the asset dedicated for the capacity sale. Similar to when it sells capacity, when GMO purchases capacity to assure it can meet its load with energy, it will pay a demand component (fixed charge) to the seller. These demand components are assigned or allocated to the jurisdictions with a demand allocator. However, energy sold or purchased using that capacity is a variable cost and is allocated to the jurisdictions with energy allocation factors.

GMO meets its native load with the same generating plant and transmission plant that it uses to generate and transport electricity to make off-system sales—sales to firm and non-firm customers in the bulk power markets (off-system sales). Staff also used the Missouri retail jurisdictional energy allocation factor to allocate GMO's revenues from off-system sales to its Missouri retail jurisdiction. Since the non-firm, off-system sales market is made up of short-term sales, GMO does not reserve dedicated capacity for these sales. Traditionally, off-system sales have been allocated using the energy allocation factors since the costs of making these sales are variable in nature, primarily being the cost of the fuel used to generate the electricity sold. As more megawatts are sold, more fuel is consumed or power purchased and, therefore, the higher the fuel cost, or the purchased power cost. These costs vary directly with the megawatt hours sold or purchased and, thus, using energy allocation factors is proper.

Staff Expert/Witness: Cary G. Featherstone

XII. Fuel Adjustment Clause ("FAC")

A. FAC - Policy

In summary, Staff makes the following recommendations regarding GMO's Fuel Adjustment Clause ("FAC") to the Commission:

1. Continue GMO's FAC with modifications;
2. Consolidate GMO's MPS and L&P Base Factors into one Base Factor and Fuel Adjustment Rates ("FARs") into one set of FARs;[100]
3. Include one new Base Factor in the FAC tariff sheets calculated from the Net Base Energy Cost[101] that the Commission includes in the revenue requirement upon which it sets GMO's consolidated general rates in this case;
4. Order GMO to suspend all of its hedging activities (cross hedging and fuel hedging);
5. Retain language in the FAC tariff sheets that would allow GMO to resume its hedging activities should the market place and/or other factors change in such a fashion that hedging would be warranted. Order GMO to notify the Commission and the Staff if it decides to resume its hedging activities between general rate cases.
6. Clarify that the only transmission costs that are included in GMO's FAC are those that GMO incurs for purchased power and off-system sales ("OSS") excluding any and all transmission costs related to GMO's Crossroads Generating plant;
7. Order GMO to exclude any and all transmission costs related to its Crossroads generating plant from the FAC; and
8. Order GMO to continue to provide the additional information as part of its monthly reports[102] as GMO was ordered[103] to do in Rate Case No. ER-2012-0175 and has continued to provide in its monthly reports.

Staff Witness/Expert: Matthew J. Barnes

1. History

Senate Bill 179[104] ("SB 179") was passed and enacted in 2005. It authorized investor-owned electric utilities to file applications with the Commission requesting authority to make periodic rate adjustments outside of general electric rate proceedings for their prudently-incurred fuel and purchased power costs. SB 179 granted the Commission the authority to approve, modify, or reject the electric utility's request. SB 179 also stated that the rate schedules

[100] If the Commission decides not to consolidate GMO's MPS and L&P rate districts, then a separate base factor would be calculated for each of GMO's MPS and L&P rate districts.
[101] Net Base Energy Cost is defined in GMO's Original Sheet No. 126.1 as "Net base energy costs ordered by the Commission in the last general rate case consistent with the costs and revenues included in the calculation of the FPA".
[102] Monthly reports are required by 4 CSR 240-3.161(5).
[103] Page 64 of the Commission's *Report and Order*, issued January 9, 2013 in File No. ER-2012-0175.
[104] Section 386.266, RSMo. 2010 Cum. Supp.

implementing these rate adjustments outside of the rate case may provide the electric utility with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased power procurement activities.

Prior to the passage of SB 179, fuel and purchased power costs were estimated and included in the determination of the utility's revenue requirement in general electric rate proceedings. If the electric utility managed its fuel and purchased power procurement and off-system sales activities in a manner that allowed it to reliably serve its customers at a net cost per kWh lower than what was included in its revenue requirement per kWh for such activities in the last general electric rate proceeding, the savings were retained by the electric utility. If actual net cost per kWh resulting from fuel and purchased power procurement and off-system sales were greater than the cost included in the revenue requirement per kWh for such activities in the last general electric rate proceeding, the electric utility absorbed the increased cost.

The Commission first authorized a FAC for GMO in its *Report and Order* in GMO's 2007 general electric rate proceeding (Case No. ER-2007-0004) for GMO's two rate districts then called Aquila Networks-MPS and Aquila Networks-L&P, with the original FAC tariff sheets becoming effective July 5, 2007. In GMO's subsequent electric rate cases, Case Nos. ER-2009-0090, ER-2010-0356, and ER-2012-0175, the Commission authorized continuation with modifications of GMO's FAC. The primary features of GMO's present FAC (tariff sheets numbered 124 through 127) include:

- Two 6-month accumulation periods: June through November and December through May;
- Two 12-month recovery periods: March through February and September through August;
- Separate Fuel Adjustment Rates ("FARs") for MPS and for L&P;
- Two FAR filings annually not later than January 1 and July 1;
- A 95%/5% sharing mechanism;
- FARs for individual service classifications are adjusted for the two service voltage levels of GMO's MPS and L&P rate districts, rounded to the nearest $0.00001, and charged on each applicable kWh billed; and
- True-up of any over- or under-recovery of revenues following each recovery period with true-up amounts being included in determination of FARs for a subsequent recovery period.

Base Factors for GMO's MPS and L&P rate districts (base energy cost per kWh rates) were originally set in GMO's 2007 rate case (Case No. ER-2007-0004) to be $0.02538 per kWh for MPS and $0.01799 per kWh for L&P. In GMO's 2009 rate case (Case No. ER-2009-0090), the Company did not propose to re-base the Base Factors. Despite its original proposal not to change them, GMO agreed to reset the Base Factors to $0.02349 per kWh for MPS and $0.01642 per kWh for L&P as part of a non-unanimous stipulation and agreement.[105] In its next general rate case (Case No. ER-2010-0356), again, GMO did not propose to re-base the Base Factors. In that case, Staff again strongly opposed the Company's proposal to not re-base its base energy cost per kWh rates. In its *Report and Order* in that case, the Commission resolved this contested issue and directed that the base energy cost per kWh rates be re-based.[106] As a result of this order, the Base Factors were set at $0.02340 per kWh for MPS and $0.01936 per kWh for L&P. In GMO's 2011 rate case (Case No. ER-2012-0175), GMO re-based the Base Factors to $0.02278 per kWh for MPS and $0.02076 per kWh for L&P.

In the current rate case (Case No. ER-2016-0156), GMO is proposing to consolidate GMO's MPS and L&P rate districts and calculate the Base Factor on a combined GMO basis. Staff is also proposing a consolidation of GMO's MPS and L&P base factors.

Staff Expert/Witness: Matthew J. Barnes

2. <u>Continuation of FAC</u>

Staff recommends that the Commission approve, with modifications, the continuation of GMO's FAC. Staff also recommends that the Commission consolidate GMO's MPS and L&P Base Factors into one consolidated GMO Base Factor. At this time Staff does not have its estimate for the Base Factor for the FAC, but will provide it and a discussion on the calculation of the Base Factor when Staff files its Class Cost of Service/Rate Design Report on July 29, 2016. Staff will use the Net Base Energy Cost and the kWh at the generator from its fuel run to develop the Base Factor.

The Company has filed for and received approval of changes to its FARs for seventeen (17) completed accumulation periods ("AP") (AP1 through AP17). Chart 1 shows the MPS and L&P FARs for each accumulation period.

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[105] *Non-Unanimous Stipulation and Agreement*, filed on May 22, 2009.
[106] See Case No. ER-2010-0356: *Report and Order* dated May 4, 2011 concerning Decision – FAC Rebasing on pages 208 – 209.

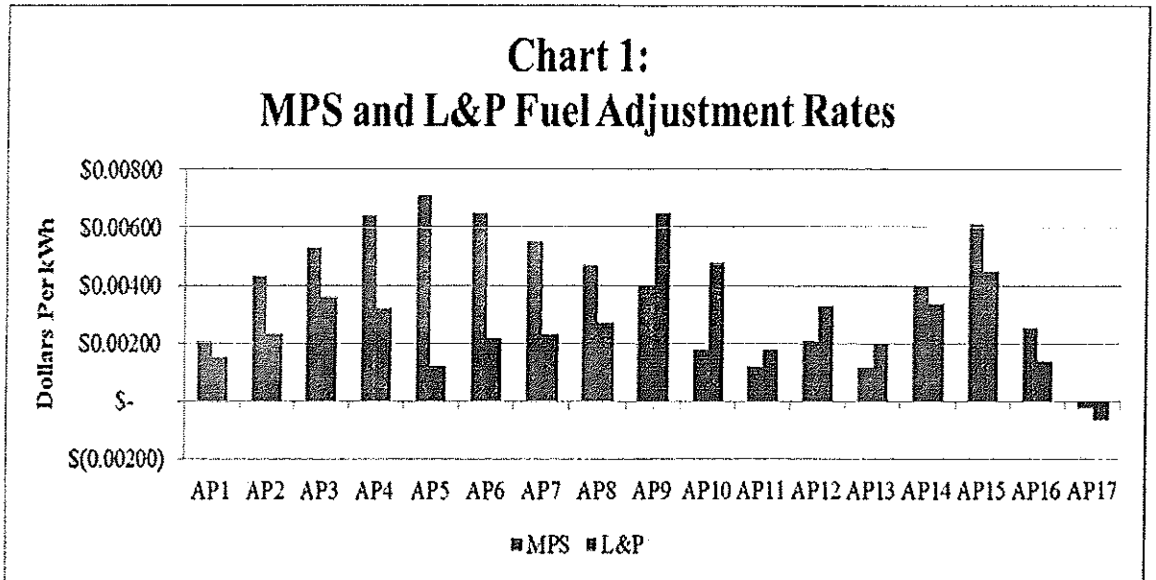

Chart 1:
MPS and L&P Fuel Adjustment Rates

The time periods for the accumulation periods ("APs") are as follows:

AP1: Jun 2007 – Nov 2007	AP2: Dec 2007 – May 2008
AP3: Jun 2008 – Nov 2008	AP4: Dec 2008 – May 2009
AP5: Jun 2009 – Nov 2009	AP6: Dec 2009 – May 2010
AP7: Jun 2010 – Nov 2010	AP8: Dec 2010 – May 2011
AP9: Jun 2011 – Nov 2011	AP10: Dec 2011 – May 2012
AP11: Jun 2012 – Nov 2012	AP12: Dec 2012 – May 2013
AP13: Jun 2013 – Nov 2013	AP14: Dec 2013 – May 2014
AP15: Jun 2014 – Nov 2014	AP16: Dec 2014 – May 2015
AP17: Jun 2015 – Nov 2015	

Chart 2 shows GMO's Actual Net Energy Cost has exceeded the then-effective Base Factors multiplied by monthly usage billed to GMO's customers in fourteen (14) out of seventeen (17) completed accumulation periods.

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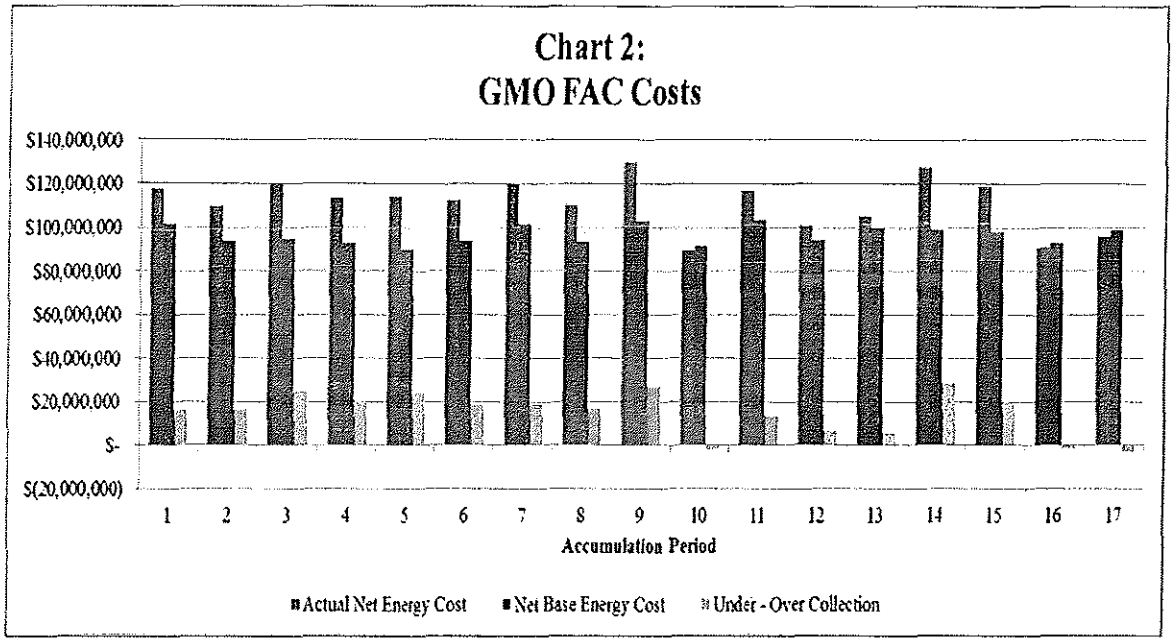


Actual FAC costs include: GMO's total booked costs as allocated for fuel consumed in the Company's generating units, including the costs associated with the Company's fuel hedging program; purchased power energy charges, including applicable transmission fees; SPP variable costs; air quality control system consumables, such as anhydrous ammonia, limestone, and powder activated carbon, and net emission allowance costs. Actual FAC costs are off-set by actual revenue from Off-System Sales and actual Renewable Energy Credit Revenues. During three accumulation periods, AP10, AP16 and AP17, GMO's Net Base Energy Cost exceeded Actual Net Energy Cost; 95% of such excess amounts were returned to customers during three recovery periods ("RP") RP10, RP16, and RP17. In fourteen of its accumulation periods (AP1, AP2, AP3, AP4, AP5, AP6, AP7, AP8, AP9, AP11, AP12, AP13, AP14 and AP15), GMO under-collected its Actual Net Energy Costs, and 95% of the amounts of under-collection were recovered from GMO's customers during recovery periods RP1, RP2, RP3, RP4, RP5, RP6, RP7, RP8, RP9, RP11, RP12, RP13, RP14, and RP15.

Charts 3 and 4 illustrate the following information for the first seventeen (17) accumulation periods: (1) cumulative under collection amount which is equal to Actual Net Energy Cost ("ANEC") less Net Base Energy Cost ("B") for GMO,[107] and (2) percentage of cumulative under-collection amount which is equal to 100*(ANEC-B)/ANEC.

[107] For AP17, this is the amount on line 5 of GMO's 11th Revised Sheet No. 127.

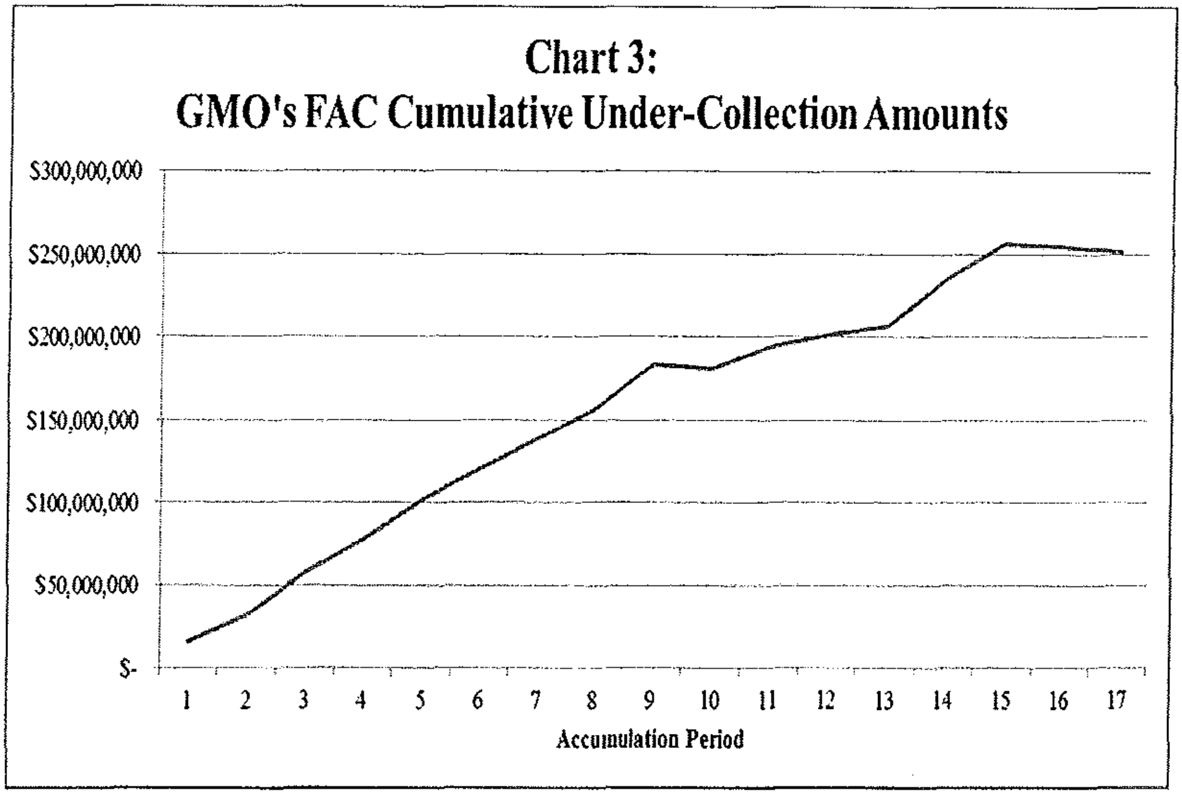


Chart 3:
GMO's FAC Cumulative Under-Collection Amounts
$300,000,000
$250,000,000
$200,000,000
$150,000,000
$100,000,000
$50,000,000
$-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17
Accumulation Period

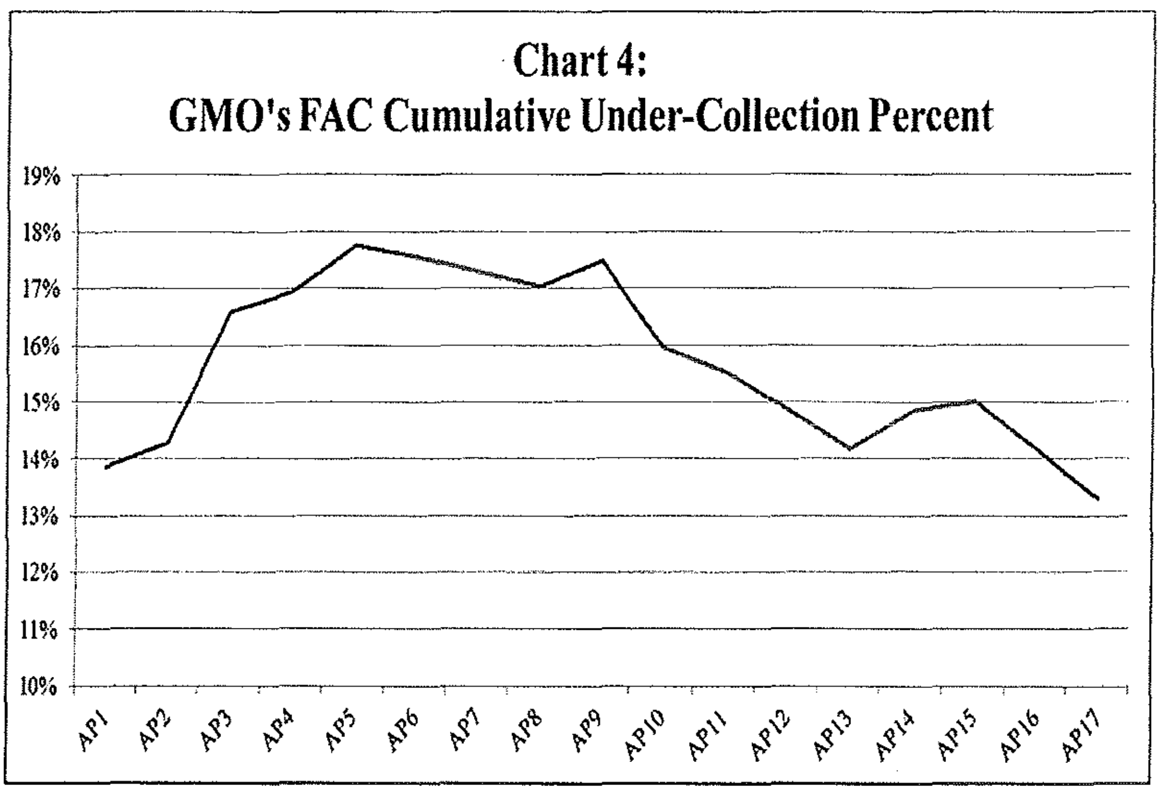


Chart 4:
GMO's FAC Cumulative Under-Collection Percent
19%
18%
17%
16%
15%
14%
13%
12%
11%
10%
AP1 AP2 AP3 AP4 AP5 AP6 AP7 AP8 AP9 AP10 AP11 AP12 AP13 AP14 AP15 AP16 AP17

Chart 2 illustrates the variability of the FARs as a result of variations in each accumulation period's billed Net Base Energy Cost and Actual Net Energy Cost. From Charts 3 and 4, Staff observes that the FAC cumulative under-collected amount over nine years is approximately $250 million or about 13 percent of total Actual Net Energy Cost, which totaled $1,893 million during AP1 through AP17.

Staff recommends continuation of GMO's FAC with modifications. As shown in the previous charts and discussion, GMO's Actual Net Energy Costs continue to be relatively large,[108] volatile, and beyond the control of the Company. In addition, the SPP conversion to the Integrated Marketplace ("IM") on March 1, 2014, represents a fundamental change in how GMO's generation is dispatched and how GMO serves its native load. By having an FAC that includes IM costs, the effects of the IM will flow through the FAC to both the Company and its customers in a timely manner. Staff will provide an exemplar tariff that includes language concerning GMO's participation in the IM in Staff's CCOS and Rate Design report.

Staff Expert/Witness: Matthew J. Barnes

3. Crossroads Transmission Costs

Staff recommends that the Commission order the following transmission costs reflected in FERC Account Number 565 be included in GMO's FAC, and order that any and all MISO transmission charges for GMO's Crossroads generating plant be excluded from GMO's FAC:

> Subaccount 565000: non-SPP transmission used to serve off-system sales or to make purchases for load and a percent[109] of the SPP transmission service costs which includes the schedules listed below as well as any adjustments to the charges (excluding any and all MISO transmission charges for GMO's Crossroads generating plant) in the schedules below:
>
> Schedule 7 – Long Term Firm and Short Term Point to Point Transmission Service (excluding any and all MISO transmission charges for GMO's Crossroads generating plant);

[108] GMO's proposed Base Energy Cost for this case represents 37% of the requested total revenue requirement.
[109] The percent of SPP transmission service costs will be calculated with the Base Factor to be filed in Staff's Class Cost of Service Report on July 29, 2016.

> Schedule 8 – Non Firm Point to Point Transmission Service (excluding any and all MISO transmission charges for GMO's Crossroads generating plant);
>
> Schedule 9 – Network Integration Transmission Service (excluding any and all MISO transmission charges for GMO's Crossroads generating plant);
>
> Schedule 10 – Wholesale Distribution Service (excluding any and all MISO transmission charges for GMO's Crossroads generating plant);
>
> Schedule 11 – Base Plan Zonal Charge and Region Wide Charge (excluding any and all MISO transmission charges for GMO's Crossroads generating plant);
>
> Subaccount 565020: the allocation of the allowed costs in the 565000 account attributed to native load (excluding any and all MISO transmission charges for GMO's Crossroads generating plant);
>
> Subaccount 565027: the allocation of the allowed costs in the 565000 account attributed to transmission demand charges (excluding any and all MISO transmission charges for GMO's Crossroads generating plant); and
>
> Subaccount 565030: the allocation of the allowed costs in account 565000 attributed to off-system sales (excluding any and all MISO transmission charges for GMO's Crossroads generating plant).

The Commission's *Report and Order* issued in GMO's last general rate case, File No. ER-2012-0175, stated on page 64:

> Crossroads Transmission. Several parties ask the Commission to order that GMO's FAC tariff sheets state expressly that GMO's FAC excludes transmission costs related to Crossroads. Insofar as the Commission has determined that no transmission costs from Crossroads will enter GMO's MPS rates, there is no further dispute, and no further findings of fact and conclusion of law are required. The Commission will order GMO's FAC clarified to state that GMO's FAC excludes transmission costs related to Crossroads.

During the course of Staff's investigation into GMO's transmission expense for this general rate case, Staff discovered that GMO has in fact been including some MISO transmission expenses as a result of GMO's portion of the Crossroads generating plant in the FAC. Following several discussions between Staff and GMO on this issue, GMO indicated to Staff that it planned on including $4,591,333 including interest in its next FAC true-up filing to correct for its error. GMO filed its FAC true-up filing on July 1, 2016, in File No. ER-2017-0002. In Company witness Linda J. Nunn's direct testimony on page 5, line 11, through page 7, line 17, in File No. ER-2017-0002, she states the following concerning Crossroads transmission expense:

> Q: Please explain the need for the corrections indicated above.
>
> A: In the Reports and Orders for Rate Case Nos. ER-2010-0356 effective May 14, 2011, and ER-2012-0175 effective January 9, 2013, the Commission expressly ordered that Crossroads transmission costs would be excluded from both base rates and the FAC. GMO has inadvertently included a portion of Crossroads transmission expenses in the calculation of the FAC.
>
> Q: What process has been used by GMO to exclude Crossroads transmission costs from the FAC?
>
> A: Monthly, GMO calculates the over/under for the FAC and makes a corresponding entry on its books. The process in place has been to take total transmission expense and then remove the items not allowable through the FAC including the removal of all Crossroads transmission charges.
>
> Q: Did this work in the past?
>
> A: Yes.
>
> Q: What changed to cause this process to no longer work?
>
> A: Prior to the time that Entergy joined the Regional Transmission Organization Midcontinent Independent System Operator ("MISO"), GMO would have monthly MISO charges for transmission related to purchased power that traveled through the MISO territory (completely unrelated to Crossroads). Those costs were allowable in the FAC according to the tariff as they were transmission for purchased power to serve native load. When Entergy joined MISO late in 2013, the transmission costs related to

Crossroads began to be billed by MISO (previously billed by Entergy) and the accounting reports used to prepare the FAC calculation included a line item which identified Crossroads charges. There were other line items on the MISO bill that did not indicate a Crossroads connection. It turns out that the line item labeled Crossroads was for Schedule 7 fees only. The Company removed the amount associated with that schedule (Schedule 7 – Demand) from the FAC calculation. However, the Company did not realize that the other MISO charges identified on the reports not labeled Crossroads were actually associated with the Crossroads facility.

Q: How was this error discovered?

A: This came to light while doing some additional accounting research for the current GMO rate case. It became clear that charges for MISO included on FERC schedules 1, 2, 26, 33, and 45 related to the Crossroads facility were inadvertently allowed to flow through GMO FACs.

Q: How will this error be corrected?

A: The correction of this error with interest has been included in this true-up calculation. Schedule LJN-1 includes the monthly correction amount along with the interest calculation that totals the MPS and L&P correction made in this true up filing.

Q: What steps have been taken to ensure that an error like this will not happen in the future?

A: Accounting procedure has now been changed so that any charge from MISO is to be considered related to Crossroads unless the front office takes action to notify Accounting that a non-Crossroads deal has been made.

Q: Do these types of power trades happen frequently?

A: Not anymore. With the implementation of the Southwest Power Pool Integrated Market in March 2014, the need for these types of deals has dropped dramatically.

Q: Have any MISO power deals been completed since Entergy joined MISO that should be included in the FAC?

A: Yes. To date, the last power trades completed with MISO were in February 2014.

Staff's recommendation to exclude Crossroads transmission expense from permanent rates and the FAC for this general rate case are discussed in more detail in the testimony of Staff witness Cary G. Featherstone.

Staff Expert/Witness: Matthew J. Barnes

B. Hedging Activities

1. History

GMO engages in hedging activities in an effort to reduce the risk of operating generation plants fueled by natural gas ("fuel hedging") and price risk associated with electrical energy purchases ("cross hedging"). GMO attempts to manage these risks through a process of purchasing New York Mercantile Exchange ("NYMEX") natural gas futures contracts.[110] GMO's hedging activities are a component of its FAC.[111] GMO's fuel hedging can be described as a traditional natural gas price hedge plan while its cross hedging program is a non-traditional natural gas price hedge plan. All of the IOU's in Missouri hedge for the natural gas fuel that is burned in its generators but only GMO uses a hedging strategy to reduce price risk of electrical energy purchases. In Case No. EO-2011-0390, Staff raised issue with GMO's cross hedging activities and recommended a disallowance associated with cross hedging losses. The Commission did not approve Staff's disallowance and all of GMO's hedging activities continued. The following chart provides a historical review of historical gains and losses associated with GMO's hedging activities.

[110] Natural gas future contracts are marketed through NYMEX (a division of the CME Group) and are financial transactions and no physical natural gas commodity will change hands.
[111] FUEL ADJUSTMENT CLAUSE – Rider FAC FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC (Applicable to Service Provided January 26, 2013 and Thereafter), ER-2012-0175 and YE-2013-0326

**

**

For the test year, GMO has experienced a net loss of ** ________ ** as a result of its hedging activities, purchased power (energy) ** ________ **and fuel ** ________ **.

Staff Expert/Witness: Dana E. Eaves

2. Market Changes

GMO participates in the SPP and since the conclusion of EO-2014-0390 SPP's market practices have significantly changed. As of March 1, 2014, SPP implemented its IM[112] in which SPP is responsible for 127 participants and 627 generating resources in 9 states.[113] ** ________ ________________________________ ________________________________ ________________ ** The price at which GMO purchases energy from the market

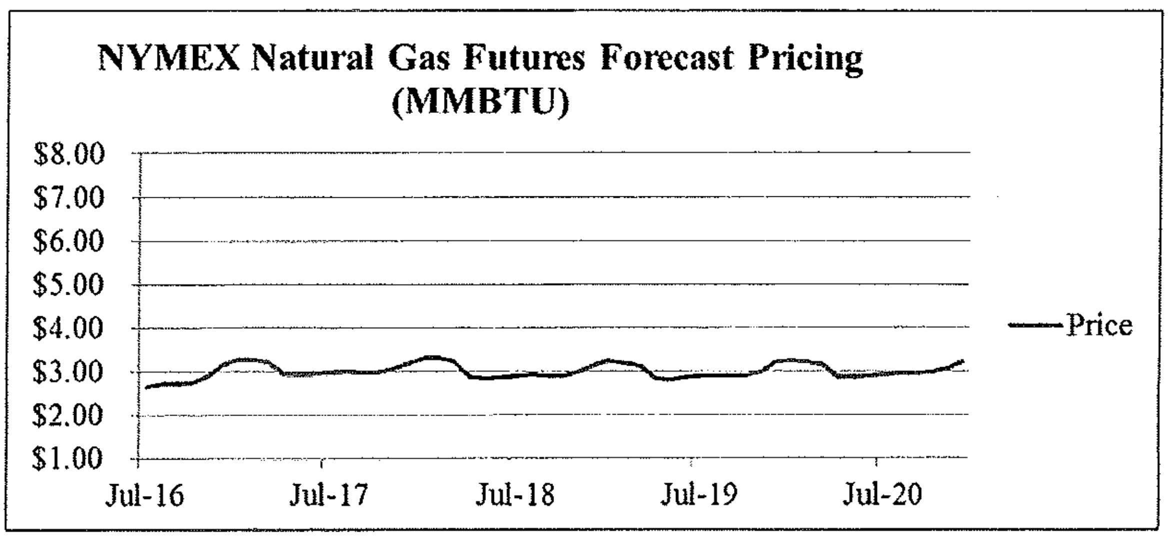
[112] Southwest Power Pool 2014 Strategic Plan, page 6; Market Operations: The Integrated Marketplace launched in 2014 and replaced the existing Energy Imbalance Service market. It includes a Day-Ahead Market with Transmission Congestion Rights, a Reliability Unit Commitment process, a Real-Time Balancing Market replacing the EIS Market, and the incorporation of price-based Operating Reserve procurement. It is expected to yield its more than 115 participants up to $100 million in annual net savings by allowing load serving participants to use the least expensive available energy in the SPP footprint regardless of ownership while maintaining the reliability of the transmission system. It also allows generation owning participants another avenue to sell their energy.
[113] http://www.spp.org/publications/Intro_to_SPP_October%202014.pdf.

NP

will be at a Locational Marginal Price ("LMP")[114] set hourly by SPP that reflects a regional market price. One of the main purposes of SPP is to fully optimize the system resources so that the least cost generation is used in the production of energy. GMO's current hedging policies simply have no effect on the actual price of energy.

GMO's FAC protects both shareholders and rate payers from unexpected changes in fuel and purchased power costs. The FAC protects shareholders by allowing GMO to bill customers for actual fuel and purchased power costs through periodic rate adjustment filings. Customers are protected from price fluctuations resulting from these same periodic rate adjustments. As fuel and purchased power prices rise or fall customers are billed the incremental difference over an extended period of time.[115]

Natural gas prices have stabilized and are expected to remain stable. While consumption of natural gas used to generate electricity has increased significantly in recent years, natural gas inventories remain at an all-time high primarily due to economic extraction of natural gas from shale formations.



Staff Expert/Witness: Dana E. Eaves

[114] LMP = Market Price of Energy + Congestion Charges + Losses.
[115] GMO's Rider FAC allows for 2 six-month accumulation periods (June-November, December-May) and 2 twelve-month recovery periods (March-February, September-August).

3. Recommendation

Staff recommends the Commission order GMO to suspend all of its hedging activities (cross hedging and natural gas fuel hedging) associated with natural gas.

GMO's FAC Rider Tariff Sheet should retain language that will allow GMO to resume its natural gas **fuel** hedging activities should the market place and/or other factors change such that resuming natural gas fuel hedging activities would again be warranted. GMO should notify the Commission and the Staff if it decides to resume its natural gas fuel hedging activities in between general rate cases.

Staff is proposing Adjustment E-47.1 to the GMO consolidated accounting schedules. This adjustment reflects the removal of test year dollars from permanent rates and the FAC base factor for natural gas hedging. However, GMO would still be able to wind-up its natural gas hedging transactions currently in place and seek recovery through its FAC Rider.

Staff Expert/Witness: Dana E. Eaves

4. Southwest Power Pool ("SPP") Integrated Market

On February 1, 2007, SPP started the Energy Imbalance Services (EIS) Market when it began dispatching wholesale electricity. The wholesale energy market is intended to allow for more efficient deployment of generation across the SPP region through the establishment of an offer-based market for energy imbalance services. The EIS Market was decommissioned March 11, 2014, following the start of the IM ten days earlier, on March 1, 2014. The IM is a market expansion which added a market functionality that coordinates next-day generation across the SPP region with the goals of maximizing cost-effectiveness, providing participants with greater access to reserve energy, improving regional balancing of electricity supply and demand, and facilitating the integration of renewable resources. Specifically, the Integrated Marketplace includes:

- A day-ahead market with transmission congestion rights ("TCRs");
- A reliability unit commitment process;
- A real-time balancing market replacing SPP's EIS market;
- Incorporation of a price-based operating reserve market;
- Combining current balancing authorities into a single SPP balancing authority.

GMO is registered in the SPP IM as both a generating and load-serving entity. Staff recommends the Commission revise GMO's FAC Tariff Sheets and Base Factor in this case to reflect GMO's participation in the SPP IM.

Staff Expert/Witness: Matthew J. Barnes

C. Revising the Base Factor

Correctly setting the Base Factor in GMO's FAC tariff sheets is critical to both a well-functioning FAC and a well-functioning FAC sharing mechanism. For the reasons below, Staff recommends the Commission require the Base Factor in GMO's FAC be set based on the Base Energy Cost that the Commission includes in the revenue requirement which it sets GMO's general rates in this case.

Table 1 below shows three scenarios in which the FAC Base Energy Cost used to set the FAC Base Factor are equal to, less than, or greater than the Base Energy Cost in the revenue requirement upon which the Commission sets general rates:

Table 1: Base Energy Cost Case Studies

Line	**95%/5% Sharing Mechanism**	Case 1 Energy Cost in FAC **Equal To** Base Energy Cost in Rev. Req.	Case 2 Energy Cost in FAC **Less Than** Base Energy Cost in Rev. Req.	Case 3 Energy Cost in FAC **Greater Than** Base Energy Cost in
a	Revenue Requirement	$ 10,000,000	$ 10,000,000	$ 10,000,000
b	Base Energy Cost in Rev. Req.	$ 4,000,000	$ 4,000,000	$ 4,000,000
c	Base Energy Cost in FAC	$ 4,000,000	$ 3,900,000	$ 4,100,000
	Outcome 1: Actual Energy Cost **Greater Than** Base Energy Cost in Revenue Requirement			
d	Actual Total Energy Cost	$ 4,200,000	$ 4,200,000	$ 4,200,000
	Billed to Customer:			
= b	in Permanent Rates	$ 4,000,000	$ 4,000,000	$ 4,000,000
e = (d - c) x 0.95	through FAC	$ 190,000	$ 285,000	$ 95,000
f= b + e	Total Billed to Customers	$ 4,190,000	$ 4,285,000	$ 4,095,000
g = f - d	**Kept/(Paid) by Company**	**$ (10,000)**	**$ 85,000**	**$ (105,000)**
	Outcome 2: Actual Energy Cost **Less Than** Base Energy Cost in Revenue Requirement			
h	Actual Energy Cost	$ 3,800,000	$ 3,800,000	$ 3,800,000
	Billed to Customer:			
= b	in Permanent Rates	$ 4,000,000	$ 4,000,000	$ 4,000,000
i = (h - c) x 0.95	through FAC	$ (190,000)	$ (95,000)	$ (285,000)
j = b + i	Total Billed to Customers	$ 3,810,000	$ 3,905,000	$ 3,715,000
k = j - h	**Kept/(Paid) by Company**	**$ 10,000**	**$ 105,000**	**$ (85,000)**

Case 1 illustrates that if the FAC Base Energy Cost used for the Base Factor is equal to the Base Energy Cost in the revenue requirement used for setting general rates, the utility does not over or under-collect as a result of the level of total actual energy costs. The FAC works as it is intended to.

Case 2 illustrates that if the FAC Base Energy Cost used for the Base Factor is less than the Base Energy Cost in the revenue requirement used for setting general rates, the utility will collect more than was intended and customers pay more than the FAC was designed for them to pay, regardless of the level of actual energy costs.

Case 3 illustrates that if the FAC Base Energy Cost used for the Base Factor is greater than the Base Energy Cost in the revenue requirement used for setting general rates, the utility will not collect all of the costs that was intended in the FAC design, and customers pay less than the entire amount intended regardless of the level of actual energy costs.

These three cases illustrate the importance of setting the Base Factor in the FAC correctly, i.e., revising the Base Factor to match the Base Energy Cost in the revenue requirement used for setting general rates. Case 1 is the preferred case, and illustrates how the FAC is intended to work.

Staff Expert/Witness: Matthew J. Barnes

D. Additional Reporting Requirements

Due to the accelerated Staff review process necessary with FAC adjustment filings,[116] Staff recommends the Commission order GMO to continue to provide the following information as part of its monthly reports as GMO agreed to do in the Commission's *Report and Order* issued January 9, 2013, in Rate Case No. ER-2012-0175, and has continued to provide in its monthly reports;

1. Monthly Southwest Power Pool ("SPP") market settlements and revenue neutrality uplift charges;
2. Notify Staff within 30 days of entering a new long-term contract for transportation, coal, natural gas or other fuel; natural gas spot transactions are specifically excluded;

[116] The company must file its FAC adjustment 60 days prior to the effective date of its proposed tariff sheet. Staff has 30 days to review the filing and make a recommendation to the Commission. The Commission then has 30 days to approve or deny Staff's recommendation.

3. Provide Staff with a monthly natural gas fuel report that includes all transactions, spot and longer term; the report will include term, volumes, price and analysis of number of bids;

4. Notify Staff within 30 days of any material change in GMO's fuel hedging policy, and provide the Staff with access to new written policy;

5. Provide Staff its Missouri Fuel Adjustment Interest calculation workpapers in electronic format with all formulas intact when GMO files for a change in the cost adjustment factor;

6. Notify Staff within 30 days of any change in GMO's internal policies for participating in the SPP;

7. Continue to provide Staff access to all contracts and policies upon Staff's request, at GMO's corporate office in Kansas City, Missouri.

Staff Expert/Witness: Matthew J. Barnes

XIII. Other Miscellaneous Items

A. Clean Charge Network O&M and Rate Base

Pursuant to the Commission's *Report and Order* in KCPL Case No. ER-2014-0370, Staff recommends removal of the operations and maintenance ("O&M") expense, plant in service, and accumulated depreciation reserve related to the Clean Charge Network from the cost of service. The Commission denied recovery of the vehicle chargers installed under the Clean Charge Network program on page 75 of its *Report and Order*:

> While the Commission believes that it would be beneficial to move forward with the Clean Charge Network, it is premature to require KCPL's customers to bear the costs of the program. The Commission concludes that KCPL has failed to meet its burden of proof to demonstrate that the charging stations placed in service in its Missouri service territory as of May 31, 2015, should be included in rate base as a part of the revenue requirement for this case, so that request will be denied. The Commission will establish a working case in order to address the legal and long-term policy issues relating to the Clean Charge Network.

Therefore, Staff recommends the removal of the O&M expense, plant in service, and accumulated depreciation reserve related to the Clean Charge Network from the cost of service. Staff's adjustments are identified on Schedule 9 of Staff's GMO consolidated, MPS and L&P Accounting Schedules, Adjustment E-106.2, and Schedule 3 – Plant in Service, Adjustments

P-315.1 and P-314.1, and Schedule 6 – Accumulated Depreciation Reserve, Adjustments R-315.1 and R-314.1.

Staff Experts/Witnesses: Keith Majors

B. GMO's MEEIA Summary

GMO filed its first Missouri Energy Efficiency Investment Act ("MEEIA") application for approval of Demand-Side Management ("DSM") programs and for authority to establish a Demand-Side Programs Investment Mechanism ("DSIM") on December 22, 2011, in Case No. EO-2012-0009. The Commission issued an order approving the *Non-Unanimous Stipulation and Agreement Resolving KCP&L Greater Missouri Operations Company's MEEIA Filing* on November 15, 2012, and GMO in accordance with the *Stipulation* began implementation of its MEEIA programs and DSIM on January 1, 2013, to run through December 31, 2015. GMO filed its second MEEIA application for approval of DSM programs and for authority to continue a DSIM on August 28, 2015, in Case No. EO-2015-0241. The Commission filed its *Report and Order* approving the application on March 2, 2016, and GMO began implementation of its second round of MEEIA programs and DSIM on April 1, 2016 to run through March 31, 2019.

GMO's DSIM rates[117] are designed to recover the MEEIA programs' costs, throughput disincentive, and an earnings opportunity through the operation of the Company's DSIM Rider.[118] GMO's DSIM rates are modified semi-annually; however, the throughput disincentive will be adjusted as a part of a general rate case and in accordance with the current DSIM tariff sheets.

Staff Expert/Witness: Brad J. Fortson

C. Test Year MEEIA Costs

Since GMO's MEEIA program costs are recovered in DSIM rates (outside of base rates), Staff made Adjustment E-133.5 to remove test year MEEIA costs from the cost-of-service calculation.

Staff Expert/Witness: Matthew R. Young

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[117] Current DSIM rates are contained in the tariff on KCP&L Greater Missouri Operations Company, P.S.C.MO. No. 1, Original Sheet No. 138.7.
[118] KCP&L Greater Missouri Operations Company, P.S.C.MO. No. 1, Original Sheet Nos. 138 – 138.8.

D. Light Emitting Diode ("LED") Street and Area Lighting ("SAL")

GMO has been directly involved in two (2) LED pilot programs between 2010 and 2013 and had access to two (2) additional LED pilot programs through its affiliation with KCPL from 2008 through 2010. GMO's direct involvement in LED pilot programs came in the form of a GMO pilot program, a KCPL pilot program, and the Mid-American Regional Council ("MARC") Smart Lights for Smart Cities pilot program. The two (2) additional LED pilot programs GMO had access to through its affiliation with KCPL were: (1) LED information sharing with the City of Kansas City, and (2) the Electric Power Research Institute ("EPRI") LED SAL project.

In 2010, the KCPL/GMO LED pilot program was conducted in conjunction with five (5) area communities during which forty-four (44) LED luminaires were installed representing the products of six (6) selected vendors.

From 2012 to 2013, GMO was also a part of the MARC Smart Lights for Smart Cities pilot program. MARC received $4 million from the United States Department of Energy to retrofit existing street lights with new high efficiency street light luminaires through a grant, ending in July 2013. This MARC project assisted GMO in understanding the future technical changes needed to improve LED street lights for utility use.

From 2008 to 2009, KCPL participated in an EPRI LED SAL project, which GMO had access to through its affiliation with KCPL. In the EPRI LED SAL project, KCPL collaborated with EPRI as a host utility to test and evaluate the potential of then-available LED lighting. Serving as a test site in the project, KCPL replaced twelve (12) of its High Intensity Discharge lighting systems with LED lighting systems.

In 2010, KCPL agreed to a LED information sharing with the City of Kansas City, Missouri ("City"), which GMO also had access to through its affiliation with KCPL. In accordance with the program, the City installed 120 LED luminaires within their customer-owned lighting circuits for testing and field measurement of lighting effectiveness. KCPL and the City agreed to share the data and results of their respective LED pilot programs.

On December 17, 2015, in Case No. ET-2016-0152, Ameren Missouri filed revised tariff sheets to add LED rates to its tariff. Ameren Missouri filed a substitute tariff sheet on December 23, 2015, to incorporate a suggested change. On December 31, 2015, Staff filed *Staff's Recommendation for Approval of Tariff Sheets* ("*Recommendation*") in that same case with a recommendation that the Commission issue an order approving the proposed tariff sheets. Staff further recommended that the Commission order Ameren Missouri to continue to provide Staff with annual updates to its economic analysis of LED street lights, as modified in Staff's *Recommendation.* On January 6, 2016, The Commission filed its *Order Regarding Tariff* ("Order") approving the revised tariff sheets, as substituted, to be effective on and after January 16, 2016. The Commission also ordered Ameren Missouri to continue to submit its annual LED report, to be modified as recommended in Staff's *Recommendation* beginning in 2016. The Commission further stated in its Order, "Approval of the tariff sheets will benefit customers in that rate class by reducing their rates, and will benefit the general public by greatly reducing energy consumption by those customers. The Commission concludes that the LED Report should be accepted, and the proposed tariff sheets should be approved."

On June 1, 2016, KCPL filed with the Commission certain revised tariff sheets for Municipal Street Lighting Service – Schedule ML.[119] The revisions requested would allow KCPL to pursue a structured conversion of all roadway lighting (non-decorative, pole mounted, over road lighting) to LED fixtures. This filing was made to incorporate LED alternatives into the KCPL tariff sheets. The revised tariff sheets went into effect on July 1, 2016.

On June 2, 2016, KCPL provided to Staff and the Public Counsel, a *LED Roadway Lighting Evaluation Summary and Conversion Proposal* ("*Report*") and workpaper to support the tariff sheet filing. Within the *Report*, KCPL states,

> Concerning deployment of LED street lighting in other KCP&L jurisdictions, the Company will evaluate options for a proposal for the KCP&L-Greater Missouri Operation (GMO) and KCP&L-Kansas jurisdictions late in 2016. In the case of GMO, there are significantly more street lights to be replaced and the effort to provide a common LED alternative is made more complex through differing rate structures for the Missouri Public Service ("MPS") and Light & Power ("L&P") portions of GMO.

On June 21, 2016, GMO provided a status update concerning LED street lighting. The status update specifically referenced the section of the *Report* mentioned in the previous paragraph and also stated, "At this time, efforts are directed at completing the above mentioned evaluation by the end of the third quarter of 2016." Through recent email correspondence, GMO has agreed to

[119] Kansas City Power and Light Company, P.S.C. MO. No. 7 Ninth Revised Sheet No. 35 – 36B.

continue to keep Staff informed, to the best extent and in as much detail as possible, by providing an annual update that includes a status report on the progress GMO has made in: (1) any conversion of its roadway lighting to LED; and (2) evaluation of the viability of converting current area lighting to LED. Staff makes no further recommendations at this time related to LED lighting.

Staff Expert/Witness: Brad J. Fortson

E. RESRAM Prudence Review

Staff's filed notice of its first prudence review of GMO's Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM") on March 11, 2016. Staff's prudence review covers costs through December 31, 2015.

GMO has included approximately $52.6 million of solar rebate payments made between September 1, 2012, and January 21, 2015, in the RESRAM, approximately $2.6 million more than the specified level of rebate payments agreed to in the *Non-Unanimous Stipulation And Agreement* in ET-2014-0059. As part of the agreement, GMO was to file an application to suspend solar rebate payments when the solar rebate payments were anticipated to reach the specified level:

> If and <u>when the solar rebate payments are anticipated to reach the specified level</u>, GMO or KCP&L will file with the Commission an application under the 60-day process as outlined in §393.1030.3 RSMo. to cease payments beyond the specified level in the year in which the specified level is reached and all future calendar years. [120]

In the direct testimony of Tim Rush in ET-2014-0277, GMO acknowledged the date and time in which it believed it received applications totaling the aggregate rebate level of $50 million:

> On November 15, 2013 at 10 AM Central Standard Time (CST), <u>the Company believed that it had received solar net metering applications that, if successfully completed, reached the aggregate rebate level of $50 million</u>. At that point, the Company subsequently informed all applicants who submitted applications received after November 15, 2013 at 10 AM CST that the aggregate rebate level had been reached. [121]

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[120] Non-unanimous stipulation and agreement ET-2014-0059, Page 3.
[121] Direct Testimony of Tim Rush, ET-2014-0277, Page 8, Lines 23-24 and Page 9, Lines 1-4 (emphasis added).

However, GMO did not file its application to suspend until April 9, 2014, after receiving solar rebate applications totaling approximately $60 million. GMO's April 2014 application to suspend solar rebate payments was ultimately approved by the Commission, and the tariff suspending solar rebate payments was effective June 8, 2014. GMO filed notice that they had paid the $50 million in solar rebate payments as of July 1, 2014, but continued to make solar rebate payments through January 21, 2015.

Staff recommends that the solar rebate payments to be included in recovery through the RESRAM be limited to the $50 million specified level which was set out in the agreement in ET-2014-0059.

In addition to paying solar rebates in excess of the stipulated cap, there are a number of issues related to the administration of solar rebate payments:

(1) A number of solar rebates were paid to customers of US Solar which were later determined to be fraudulent. ** ____________________ ____________________ **

(2) Staff is concerned that customers may have received solar rebate payments in excess of the amount that was approved by GMO to be paid. Staff is continuing to investigate this matter.

(3) Staff is concerned that there is a potential mismatch or imprecise record keeping for customers who have received solar rebate payments and GMO's spreadsheet tracking solar rebate payments. Staff is continuing to investigate this matter.

Staff Expert/Witness: Daniel I. Beck, PE

F. Tariff Issues

1. Advanced Meter Infrastructure ("AMI") Meter Installation

GMO implemented a project beginning in October 2015, to upgrade manually read meters to Advanced Meter Infrastructure ("AMI") meters with automated meter reading capabilities. Meters with these capabilities are also referred to as "smart meters." The projected result is the replacement of approximately 180,000 manually read meters or approximately 56 percent of total customer meters by September 2016.

AMI is an integrated system of meters, communication networks, and data management systems that enables two-way communication between utilities and their customers. The primary expected benefits of AMI to GMO and its customers include improved efficiency in collecting usage data, billing, outage response time and customer service.

There has been increased concern from the general public that AMI meters may contribute to ill-health effects due to Radio Frequency ("RF") radiation. Additional concerns include that AMI meters are a potential venue for invasion of privacy, information sharing, and piracy of information, as well as a potential threat for causing fires due to the meter itself overheating. Both informal and formal complaints have been filed with the PSC, in which electric utility customers request alternatives to having an AMI meter installed at their residence, citing the concerns mentioned above.[122]

Staff is not generally opposed to the installation of AMI meters and is not aware of documented proof that any negative health effects, privacy or fire risk concerns have been validated. However, given the level of customer concern in Missouri and in general across the country, Staff recommends GMO modify its tariff to create an opt-out program, which would include a provision to allow customers the option of a manually read meter rather than an AMI meter. The cost associated with any opt-out program should be cost based and borne by those customers that choose to utilize the program.

Although there are no known Missouri electric utilities that currently have opt-out programs, Staff has confirmed that several investor-owned electric utilities across the Unites States have initiated opt-out programs. These utilities include but may not be limited to: Portland General Electric Company, Central Maine Power, and Pacific Gas and Electric Company ("PG&E").

Each of these utilities' opt-out programs consists of an initial one-time charge for the placement of a manually read meter, and then a recurring monthly fee to cover the cost of physically reading the meter each month. Staff recommends that GMO implement this same type of program and cost-based fee recovery.

According to GMO's response to Data Request No. 0258, GMO is not offering an opt-out program and therefore has not performed a cost analysis for this scenario. Given the absence of

[122] In the 2016 session the Missouri House of Representatives had before it a bill to allow electric utility customers to opt out of the installation of certain types of advanced meters (House Bill 2559). The bill was assigned to a committee and a public hearing was held, though no further action occurred prior to the 2016 session adjournment.

any such analysis results, and the fact that PG&E's opt-out program fees represent the mid-range of those utilized by the three example utilities, Staff recommends that GMO implement an opt-out program with the following fees:

One-time setup charge: $75.00

Recurring monthly meter read charge: $10.00

Staff would also recommend that GMO keep track of the costs associated with the opt-out program in order to have cost data in GMO's next rate case to evaluate the one-time setup charge and recurring monthly meter read charge proposed above.

Staff understands the benefit of AMI meters and realizes that an opt-out program is counter-productive to those benefits. However, GMO will have approximately 143,000 remaining customers that will have manually read meters in place at the end of the meter upgrade project. Therefore, a mechanism to manually read customer electric meters that accounts for employees, billing software, equipment and vehicles will remain in place despite implementation of the AMI meter project. That mechanism would aid in manually reading the meters of opt-out customers.

Staff Expert/Witness: Jerry Scheible, PE

G. Renewable Energy Standard

1. Renewable Energy Costs

Since GMO's renewable energy costs are recovered outside of base rates through the RESRAM mechanism,[123] Staff made Adjustment E-135.4 to remove those costs from the test year. Staff also made Adjustment E-135.3 to remove the test year amortization of a RES vintage that has been fully recovered.[124] This vintage was included in base rates resulting from ER-2012-0175 as an amortization expense designed to recover the total deferred cost over a three-year period and was fully recovered in January 2016. Since the cost recovery was built into base rates, GMO continues to collect revenue for RES costs that have been fully recovered and will continue to collect monies for RES amortization expense until base rates are changed in this case. Staff recommends that the revenue collected for these amortizations above the amount

[123] "RESRAM" is Renewable Energy Standard Rate Adjustment Mechanism.
[124] "RES" is Renewable Energy Standard.

of deferred costs in the RES vintage be applied to current deferred RES costs or as an offset to the RESRAM mechanism.

Staff Expert/Witness: Matthew R. Young

XIV. Appendices

Appendix 1 - Staff Credentials

Appendix 2 - Support for Staff Cost of Capital Recommendation
- David Murray

Appendix 3 – Other Staff Schedules
- Erin L. Maloney, PE
- Derick A. Miles, PE
- Daniel I. Beck, PE

Appendix 4 - KCP&L Greater Missouri Operations - MPS Rate District Accounting Schedules
KCP&L Greater Missouri Operations - L&P Rate District Accounting Schedules

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0156

AFFIDAVIT OF MATTHEW J. BARNES

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

COMES NOW MATTHEW J. BARNES and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Matthew J. Barnes

MATTHEW J. BARNES

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of July, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0156

AFFIDAVIT OF ALAN J. BAX

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

COMES NOW ALAN J. BAX and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Alan J Bax

ALAN J. BAX

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of July, 2016.

D. SUZIE MANKIN
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D Suzie Mankin

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OF THE STATE OF MISSOURI

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AFFIDAVIT OF DANIEL I. BECK, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW DANIEL I. BECK, PE and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Daniel I Beck

DANIEL I. BECK, PE

JURAT

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AFFIDAVIT OF KORY BOUSTEAD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW KORY BOUSTEAD and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Kory Boustead
KORY BOUSTEAD

JURAT

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AFFIDAVIT OF SEAN M. CAHOON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW SEAN M. CAHOON and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Sean M. Cahoon
SEAN M. CAHOON

JURAT

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AFFIDAVIT OF DANA E. EAVES

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW DANA E. EAVES and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Dana E. Eaves

DANA E. EAVES

JURAT

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D. Suzie Mankin

Notary Public

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AFFIDAVIT OF CARY G. FEATHERSTONE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW CARY G. FEATHERSTONE and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Cary G. Featherstone

CARY G. FEATHERSTONE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of July, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
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Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0156

AFFIDAVIT OF BRAD J. FORTSON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW BRAD J. FORTSON and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Brad J Fortson

BRAD J. FORTSON

JURAT

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AFFIDAVIT OF ROBIN KLIETHERMES

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW ROBIN KLIETHERMES and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Robin Kliethermes

ROBIN KLIETHERMES

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of July, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
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Commission Number: 12412070

D. Suzie Mankin

Notary Public

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OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0156

AFFIDAVIT OF KAREN LYONS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW KAREN LYONS and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Karen Lyons
KAREN LYONS

JURAT

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D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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AFFIDAVIT OF KEITH MAJORS

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

COMES NOW KEITH MAJORS and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Keith Majors

KEITH MAJORS

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of July, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0156

AFFIDAVIT OF ERIN L. MALONEY, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW ERIN L. MALONEY, PE and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Erin L. Maloney, PE

ERIN L. MALONEY, PE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of July, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D. Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0156

AFFIDAVIT OF DERICK A. MILES, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW DERICK A. MILES, PE and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Derick A Miles

DERICK A. MILES, PE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of July, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0156

AFFIDAVIT OF DAVID MURRAY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW DAVID MURRAY and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

DAVID MURRAY

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of July, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0156

AFFIDAVIT OF CHARLES T. POSTON, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW CHARLES T. POSTON, PE and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

CHARLES T. POSTON, PE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of July, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D. Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0156

AFFIDAVIT OF ASHLEY SARVER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW ASHLEY SARVER and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement- Cost of Service; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Ashley Sarver
ASHLEY SARVER

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of July, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
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D. Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0156

AFFIDAVIT OF JERRY SCHEIBLE, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW JERRY SCHEIBLE, PE and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement- Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Jerry Scheible

JERRY SCHEIBLE, PE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 7th day of July, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0156

AFFIDAVIT OF MICHAEL L. STAHLMAN

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

COMES NOW MICHAEL L. STAHLMAN and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

MICHAEL L. STAHLMAN

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of July, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0156

AFFIDAVIT OF MICHAEL JASON TAYLOR

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW MICHAEL JASON TAYLOR and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Michael Jason Taylor

MICHAEL JASON TAYLOR

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of July, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0156

AFFIDAVIT OF SEOUNG JOUN WON, PhD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW SEOUNG JOUN WON, PhD and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Seoung Joun Won

SEOUNG JOUN WON, PhD

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of July, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2016-0156

AFFIDAVIT OF MATTHEW R. YOUNG

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW MATTHEW R. YOUNG and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement - Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Matt Young

MATTHEW R. YOUNG

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 14th day of July, 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D. Suzie Mankin

Notary Public