MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

REVENUE REQUIREMENT
COST OF SERVICE

KCP&L – GREATER MISSOURI OPERATIONS
Great Plains Energy, Inc.

CASE NO. ER-2012-0175

Jefferson City, Missouri
August 9, 2012

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

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

KCP&L Greater Missouri Operations Company ("GMO," or the "Company") is a corporation duly organized and existing under the laws of the State of Delaware. GMO is a regulated public utility operating in the state of Missouri. It provides wholesale electricity to municipal customers under the jurisdiction of the Federal Energy Regulatory Commission (FERC). GMO distributes and sells electric service to the public in its certificated areas in Missouri, and is an "electrical corporation" and "public utility" subject to the jurisdiction, supervision, and control of the Missouri Public Service Commission (the "PSC" or "Commission") under Chapters 386 and 393 of the Revised Statutes of Missouri. GMO also provides industrial steam service in and about St. Joseph, Missouri, within its "L&P" rate district. GMO is wholly owned by Great Plains Energy Incorporated ("Great Plains or GPE") and is an affiliate of Kansas City Power & Light Company ("KCPL").[1] KCPL is also an "electrical corporation" and "public utility" that is subject to the jurisdiction of the Commission. KCPL and GMO collectively operate and present themselves to the public under the brand and service mark "KCP&L." 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.

1 KCPL and GMO became affiliates on July 14, 2008, when, after a Commission Order effective July 1, 2008, authorizing the acquisition, Great Plains acquired Aquila on July 14, 2008.

Approximate customer counts for GMO (Missouri) from 2006 through 2011 follow:

Year	Total	Residential	Commercial	Industrial, Municipal and other Electric Utilities
2011	312,000	274,000	38,000	500
2010	313,000	274,000	38,300	700
2009	311,000	274,000	38,000	300
2008	311,000	273,000	38,000	800
2007	308,000	270,100	N/A	N/A
2006	304,000	266,000	N/A	N/A

source: KCPL and Great Plains' 2011, 2010, 2009, 2008, 2007 and 2006 Annual Reports at pages 6 or 7, and 9; Aquila's 2007 Annual Report at page 9 and Missouri 2007, 2008, 2009, 2010 and 2011 PSC Annual Reports at pages 30 or 62..

To serve its current customers GMO owns total generating capacity of 2,139 megawatts--1,042 megawatts of coal capacity, 1,036 megawatts of natural gas-fired combustion turbine capacity, 61 megawatts of oil fired combustion turbine capacity, and it has purchased power [source: Great Plains' 2011 Annual Report at page 23].

Attachment 1, at the end of this Report, is a map of the KCPL and GMO service territories.

This case, Case No. ER-2012-0175 (herein referred to as "GMO's 2012 rate case"), is GMO's first general electric rate case after the in-service of Iatan 2 Generating Unit ("Iatan 2"). In the 2010 GMO and KCPL rate cases the Commission found that as of August 26, 2010, Iatan 2 was fully operational and used for service.

On April 4, 2007, Great Plains, KCPL, and Aquila, Inc. ("Aquila"), filed a joint application with the Commission, designated as Case No. EM-2007-0374 requesting approval for a series of transactions which ultimately would result in Great Plains acquiring Aquila's Missouri electric and steam operations, as well as its merchant services operations. These merchant services operations primarily consisted of a 297 megawatt generating facility located in Mississippi, ("Crossroads"), and certain residual natural gas contracts. The Commission approved the request in an Order effective July 1, 2008. Great Plains acquired Aquila on July 14, 2008, and later in 2008 Aquila changed its name to KCP&L Greater Missouri Operations Company.

Staff Expert/Witness: Cary G. Featherstone

II. Executive Summary

In response to GMO's February 27, 2012, application to increase its retail rates to recover an additional approximately of $58.3 million per year from its customers in the greater metropolitan Kansas City through Sedalia, Missouri, area ("MPS rate district") and to increase L&P electric rates an additional approximately $25.2 million per year from its customers in and about St. Joseph, Missouri, (L&P rate district).

Staff has reviewed of all the revenue requirement cost of service components (capital structure and return on investment; rate base investment and income statement results, including revenues; operating and maintenance expenses; depreciation expense; and related taxes, including income taxes) which comprise GMO's revenue requirements for MPS and L&P. The results of that review are presented in this Report, which includes Schedules and Accounting Schedules. The members of Staff who participated in that review are identified in the sections of the report where their results are presented in verified narrative format. The contemporaneously filed separate testimony, in question and answer format, of Daniel I. Beck, of the Commission's Utility Operations Department, and Cary G. Featherstone of the Utilities Services Department state Staff's recommended revenue requirements for MPS and L&P, which result from the analysis and recommendations described in this Report.

Staff recommends a return on equity ("ROE") range of 8.00% to 9.00%, with a mid-point of 8.5%, which yields the rate of return range of 7.14% to 7.66% for MPS and L&P. Staff's GMO revenue requirement calculation, which is based on GMO's actual costs through March 31, 2012, indicates shortfalls for MPS and L&P as follows:

GMO MPS	Rate of Return 7.14%	Rate of Return 7.66%
Revenue Requirement	$ 370,510	$11.9 million
Percentage Increase	0.1%	2.2%
Total Revenues	$545.1 million (see income statement Schedule 9)	$545.1 million
Total Revenues plus Recommended Increase	$545.4 million	$556.9 million

GMO L&P	Rate of Return 7.14%	Rate of Return 7.66%
Revenue Requirement	$707,740	$4.6 million
Percentage Increase	0.4%	2.7%
Total Revenues	$170.5 million (see income statement Schedule 9)	$170.5 million
Total Revenues plus Recommended Increase	$171.2 million	$175.1 million

Staff's MPS revenue requirement calculation, which is based on MPS actual costs through March 31, 2012, indicates the increase in revenues is approximately $370,000 to $11.9 million on current MPS rates, which generates approximately $545.1 million. With the increase of between $370,000 to $11.9 million (0.1% to 2.2%), Staff's total MPS revenue requirement recommendation is approximately $545.4 to $556.9 million.

Staff's L&P revenue requirement calculation, which is based on L&P actual costs through March 31, 2012, indicates increase in revenues is approximately $707,000 to $4.6 million on current L&P rates, which generates approximately $170.5 million. With the increase of between $707,000 to $4.6 million (0.4% to 2.7%), Staff's total L&P revenue requirement recommendation is approximately $171.2 to $175.1 million.

Because of changes expected for the true-up items through August 31, 2012, that are not known and measurable at this time, the Staff's revenue requirements for both MPS and L&P will change when the true-up is completed in this case.

Staff anticipates there will be plant additions through the August 31, 2012, the true-up period in this case, as well as cost increases in payroll and, payroll related benefits such as pensions and medical costs. Fuel prices will also be examined for any changes as part of the true-up process.

The following is a non-exhaustive list of areas in this report:

- Rate of Return
- Remaining costs for the additional plant for GMO investment in the Iatan 2 not captured in its last rate case
- GMO's investment in Iatan Common Plant not captured in its last rate case
- GMO's fuel costs, including freight rate changes and purchased power costs
- GMO's off-system sales margins from the firm and non-firm bulk power markets
- GMO's pension and other post-employment benefits (OPEBS) costs
- Acquisition savings and transition costs

Staff Expert/Witness: Cary G. Featherstone

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

GMO filed its general electric rate increase case on February 27, 2012, reflecting, on a total company basis, an annual increase in Missouri retail rate revenues of $83.5 million per year ($58.3 + $25.2 million) . The Commission designated this case as Case No. ER-2012-0175. GMO has different rates in two different geographical areas – one in and about Kansas City, which was formerly served under the d/b/a Aquila Networks - MPS and one about St. Joseph, Missouri, which was formerly served under the d/b/a Aquila Networks – L&P. For ease, the areas with differing rates are referenced as "MPS" and "L&P" in this report. For MPS, GMO requested a rate increase of $58.3 million per year, representing a 10.9% increase. For L&P

electric service, GMO requested a rate increase of $25.2 million per year, representing a 14.6% increase. These GMO requests are based on a proposed rate of return on equity of 10.4% applied to the 52.5% equity capital structure for Great Plains [source: paragraphs 6 and 7 of GMO Application- Minimum Filing Requirements page 3 and GMO Press Release].

KCPL also filed its general rate increase case on February 27, 2012, reflecting an annual increase in Missouri retail rate revenues of $105.7 million, a 15.1% increase. The Commission designated this rate case as Case No. ER-2012-0174. KCPL requested a rate of return on equity of 10.4% applied to a 52.5% equity capital structure for Great Plains [paragraphs 6 and 7 KCPL's Application- Minimum Filing Requirements page 3].

Staff Expert/Witness: Cary G. Featherstone

A. Test Year

As the Commission ordered April 19, 2012, the test year in this case, as well as the KCPL case, is the 12-month period ending September 30, 2011, updated for known and measurable changes through March 31, 2012, and trued-up through August 31, 2012. Staff's revenue requirement as presented in its Accounting Schedules includes preliminary estimates for expected changes as of the true-up cut-off date of August 31, 2012, based on current information.

Staff Expert/Witness: Cary G. Featherstone

B. True-up Case

Because of anticipated cost increases, including plant additions at GMO's request the Commission established a true-up through the August 31, 2012.

Staff Expert/Witness: Cary G. Featherstone

IV. GMO has filed for the following rate increases for MPS and L&P

MPS rate increases are:

Case No.	Date Filed	MPS Amount Requested	MPS Amount Authorized	L&P Amount Requested	L&P Amount Authorized	Effective Date of Rates
ER-2007-0004	July 3, 2006	$94.5 million (22% increase)	$ 45.3 million (11.64% increase)	$22.4 million (22.1% increase)	$13.6 million (12.79% increase)	June 3, 2007
ER-2009-0090	September 5, 2008	$ 66 million (14.4 % increase excluding any impact of the fuel clause)	$48 million (10.46% increase)	$ 17.1 million (14.4 % increase excluding any impact of the fuel clause)	$15 million (11.85% increase)	September 1, 2009
ER-2010-0356	June 4, 2010	$75.8 million (14.4% increase excluding impact of the fuel clause)	$35.7 million (7.2%)	$22.1 million (13.9% increase excluding impact of the fuel clause)	$22.1 million (15.8%) Full amount before phase-in of $29.8 million excluding deferrals	June 25, 2011

Staff did a comparison of GMO's electric rates in Missouri with other electric utilities in Missouri and Kansas. Based on information by the Edison Electric Institute that KCPL in turn provided in response to a Staff data request, the rates KCPL and GMO charge its Missouri residential customers are below the national average and generally below those of other Missouri and mid-western utilities.

The following table shows such a comparison of GMO's actual composite residential customer rates its MPS and L&P rate districts as of January 1, 2012:

Continued on next page.

Missouri and Kansas Residential-in cents per kilowatt hour	2011	2010	2009	2008	2007	2006	2005
MISSOURI RATES							
KCPL-Missouri	9.90 cents/kwh	9.53	8.51	8.14	7.61	6.90	6.88
MPS	**10.81**	**10.52**	**9.67**	**9.10**	**8.64**	**8.08**	**7.45**
L&P	**8.64** **Does not include Phase 2 rates in effect June 2012**	**7.97**	**7.43**	**7.03**	**6.78**	**6.31**	**5.97**
Ameren Missouri	8.80	7.82	7.03	6.53	6.60	6.60	6.52
Empire- Missouri	11.22	9.95	9.75	9.19	9.10	8.35	7.98
Missouri Average	**9.39**	**8.54**	**7.77**	**7.27**	**7.18**	**6.96**	**6.77**
KANSAS RATES							
KCPL- Kansas	10.58	9.67	9.07	8.43	7.43	6.92	6.88
Empire - Kansas	10.53	9.65	8.97	9.26	9.20	8.69	7.11
Westar Energy -- KGE	9.92	9.46	8.84	7.84	7.29	7.72	7.74
Westar Energy -- KPL	9.93	9.55	9.17	8.07	7.16	7.36	6.69
Kansas Average	10.12	9.56	9.03	8.12	7.31	7.51	7.27
United States Average	**12.07**	**12.01**	**11.72**	**11.53**	**10.95**	**10.62**	**9.60**

Source: EEI Winter 2010 Report, page 180 provided Data Request 380- ER-2010-0355
EEI Winter 2012 Report, page 212 provided Data Request 241- ER-2012-0174

As shown in the table below, GMO's commercial rates in MPS are now, and for several years have been higher than those in L&P, and higher than KCPL's, while GMO's commercial rates in L&P are lower than the Missouri average, with GMO commercial rates in MPS are higher than the Missouri average, but GMO's commercial rates in MPS and L&P are all below the United States national average:

Missouri and Kansas Commercial-in cents per kilowatt hour	2011	2010	2009	2008	2007	2006	2005
MISSOURI RATES							
KCPL-Missouri	7.62 cents/kwh	7.31	6.56	6.22	5.92	5.49	5.48
MPS	**8.45**	**8.25**	**7.62**	**7.08**	**6.59**	**6.16**	**5.94**
L&P	**7.36** **Does not include Phase 2 rates in effect June 2012**	**6.69**	**6.26**	**5.86**	**5.51**	**5.26**	**5.37**
Ameren Missouri	6.92	6.29	5.71	5.34	5.34	5.32	5.29
Empire- Missouri	9.94	8.82	8.60	8.13	7.96	7.32	7.08
Missouri Average	**7.40**	**6.85**	**6.26**	**5.87**	**5.74**	**5.56**	**5.50**
KANSAS RATES							
KCPL- Kansas	8.38	7.57	7.20	6.62	6.13	5.90	5.87
Empire - Kansas	11.21	10.27	9.48	9.62	9.61	9.19	7.64
Westar Energy -- KGE	7.97	7.57	7.31	6.66	6.03	6.38	6.29
Westar Energy -- KPL	7.99	7.64	7.33	6.54	5.68	5.89	5.22
Kansas Average	8.12	7.61	7.30	6.61	5.93	6.24	5.96
United States Average	**10.20**	**10.21**	**10.03**	**10.05**	**9.53**	**9.33**	**8.67**

Source: EEI Winter 2010 Report, page 246 provided Data Request 380- ER-2010-0355
EEI Winter 2012 Report, page 244 provided Data Request 241- ER-2012-0174

The table below shows GMO's industrial rates in MPS are now and for several years have been higher than those in L&P, and higher than KCPL's, while GMO's industrial rates in MPS and L&P are higher than the Missouri average, but GMO's commercial rates in MPS and L&P are below the United States national average:

Missouri and Kansas Industrial-in cents per kilowatt hour	2011	2010	2009	2008	2007	2006	2005
MISSOURI RATES							
KCPL-Missouri	5.83 cents/kwh	5.57	5.13	4.77	4.47	4.21	4.23
MPS	**6.28**	**6.26**	**5.82**	**5.34**	**4.89**	**4.58**	**4.49**
L&P	**5.61**	**5.16**	**4.96**	**4.60**	**4.26**	**3.98**	**3.97**
Ameren Missouri	4.87	4.46	4.30	3.87	3.89	3.96	4.05
Empire- Missouri	7.72	6.89	6.60	6.19	6.08	5.51	5.41
Missouri Average	**5.30**	**4.90**	**4.73**	**4.26**	**4.18**	**4.14**	**4.61**
KANSAS RATES							
KCPL- Kansas	7.95	7.06	6.73	6.15	5.50	5.15	5.15
Empire - Kansas	8.26	7.42	7.01	6.97	6.94	6.32	5.02
Westar Energy -- KGE	5.89	5.47	5.34	4.78	4.17	4.36	4.32
Westar Energy -- KPL	6.84	6.50	6.31	5.62	4.83	5.01	4.40
Kansas Average	6.34	5.91	5.75	5.15	4.49	4.77	4.65
United States Average	**6.64**	**6.71**	**6.63**	**6.66**	**6.15**	**6.00**	**5.73**

Source: EEI Winter 2010 Report, page 278 provided Data Request 380- ER-2010-0355
EEI Winter 2012 Report, page 276 provided Data Request 241- ER-2012-0174

The above rates represent information supplied to Edison Electric Institute for publication entitled *EEI Typical Bills and Average Rate Report – Winter 2012*. Each utility who participates in the survey supplies information on its rates to EEI. The above rates relate to actual composite rates determined using actual revenue and kilowatt hour usage as of December 31 of a given year. As a cautionary note, these actual composite rates should not be confused with rates appearing in the tariff sheets of a utility. Also the commercial and industrial classes are used by federal filings such with the Securities Exchange Commission and FERC annual reports these classes do not reflect the categories of customer classes found in the tariffs of the Missouri companies.

While the information in these charts is most current available, these rates do not reflect the full year of any rate increases granted in 2011 for KCPL and GMO, or the other utilities. As an example, the KCPL rates for Missouri do not reflect the full year of rate increase for Missouri approved by the Commission in Case No. ER-2010-0355 in April 2011. Both the MPS and L&P rates appearing in the EEI rate book do not reflect the full year's annual rate impact of the Commission-approved rates in Case No. ER-2010-0356 that took effect in June 2011, nor do the rates for L&P reflect the second phase of the rate increase the Commission authorized to take effect in June 2012.

GMO filed more recent rate information for MPS and L&P in its rate application in Case No. ER-2012-0175 concerning residential rates that reflect the impact of second phase in that took effect June 2012. In its minimum filing requirements filed in File No. ER-2012-0175, GMO identified its proposed rate increase for MPS would be 11.66 cents per kilowatt hour and for L&P 10.97 cents per kilowatt hour (assuming full requested rate award). The residential rates for MPS and L&P have become closer since GMO's last rate case. In comparison, KCPL's proposed residential rate is 11.56 cents per kilowatt hour (assuming full requested rate award). If the full rate requests are granted by the Commission, KCPL's residential rates would still be between those for MPS and L&P.

Staff Expert/Witness: Cary G. Featherstone

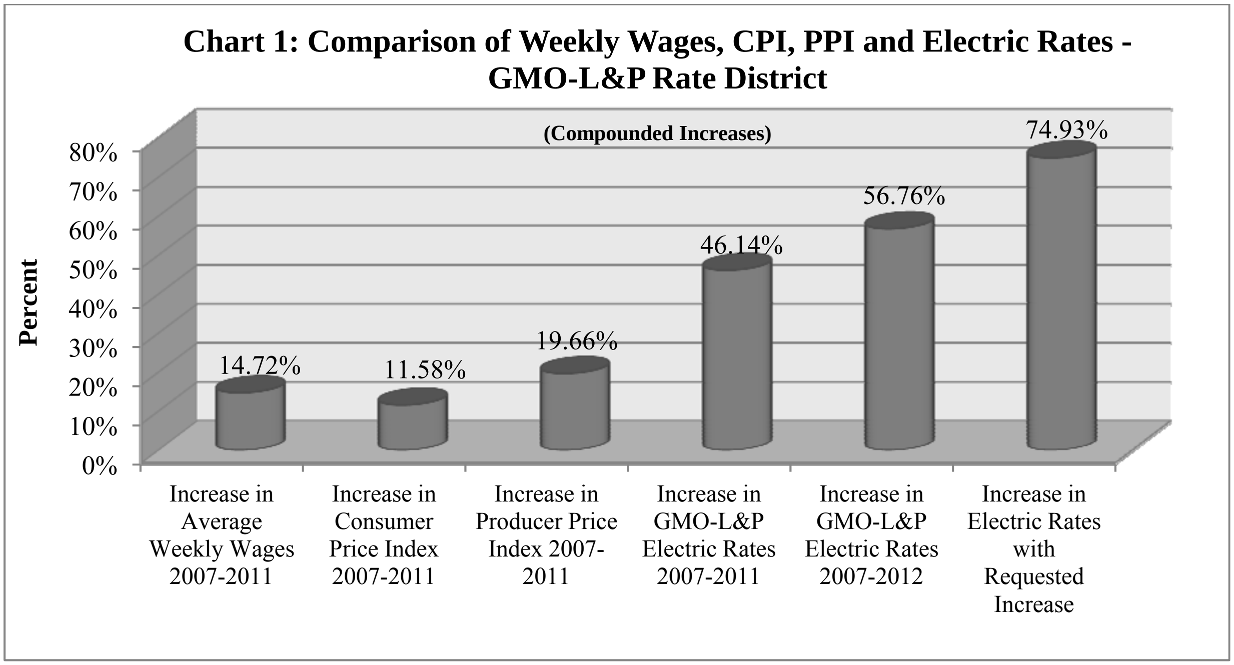
V. Economic Considerations

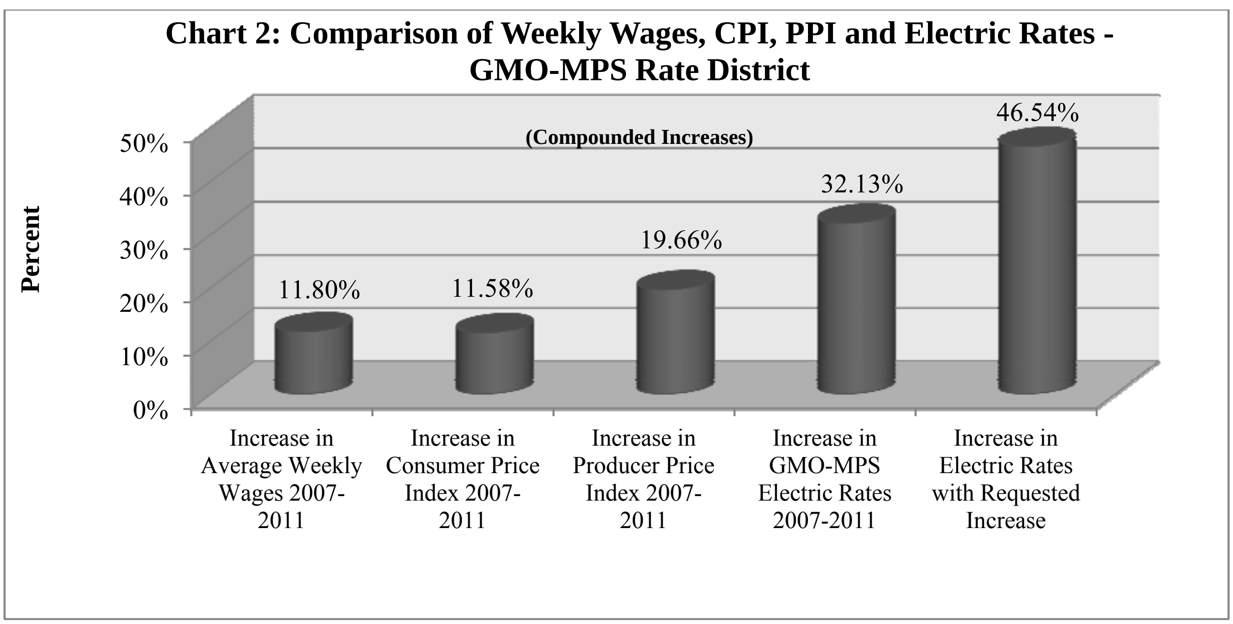
As demonstrated below, Missouri and specifically the counties[2] of the GMO service area have experienced challenging economic times since 2007 due to the recession and a slow recovery. The GMO service area includes two rate districts known as MPS ("MPS") and L&P ("L&P"), [3] where some counties are divided between both rate districts. Since different rates apply to each rate district, Chart 1 provides a comparison of the increase in average weekly

[2] According to the minimum filing requirements submitted to the Missouri Public Service Commission, KCP&L Greater Missouri Operations ("GMO") serves 31 counties in Missouri. This report does not include the 13 counties in the Kansas City Power & Light ("KCPL") service area.

[3] 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.

wages, Consumer Price Index ("CPI"), Producer Price Index ("PPI") [4] and electric rates for the L&P rate district and Chart 2 illustrates the same comparisons for the MPS rate district.





[4] The Producer Price Index for Industrial Commodities 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.

From 2007 to 2011[5] the counties in the MPS rate district collectively experienced an 11.80% increase in average weekly wages and the counties in the L&P rate district had a 14.72% increase in average weekly wages. These increases were slightly higher than the overall Missouri compounded increase in average weekly wages of 11.63%. During that same time period the Consumer Price Index ("CPI") increased 11.58% and electric rates increased 32.13% in the MPS rate district and 46.14% in the L&P rate district. These rate increases accumulated to a total increase of approximately $129 million in MPS and $51 million in L&P, shown in Table 1. However, purchasers of industrial commodities, such as GMO, have, on the average, also experienced inflationary pressure, illustrated by a 19.66% increase in the PPI for Industrial Commodities from 2007 to 2011.[6]

Table 1: GMO Rate Case History 2007-2012

Case Number	Effective Date	Dollar Value MPS	Dollar Value L&P	%Increase MPS	%Increase L&P
ER-2007-0004					
L&P	May 31, 2007		$13,583,654		12.79%
MPS	May 31, 2007	$45,253,654		11.64%	
ER-2009-0090					
L&P	September 1, 2009		$15,000,000		11.85%
MPS	September 1, 2009	$48,000,000		10.46%	
ER-2010-0356					
L&P	June 25, 2011		$22,101,088		15.84%
MPS	June 25, 2011	$35,721,372		7.15%	
ER-2012-0024					
L&P	June 25, 2012		$11,756,893		7.27%
Total 2007-2011		$128,975,026	$50,684,742	32.13%	46.14%
Total 2007-2012			$62,441,635		56.76%

The L&P rate increase of 15.84% on June 25, 2011 in Case No. ER-2010-0356 was the result of an approximately 21% increase in rates phase-in. On June 25, 2012 the next step in the phase-in took place with an increase in rates of 7.27% or $11.8 million. However, as ordered in Case No. ER-2012-0024, 2013 and 2014 rates will decrease by approximately 0.072% and

[5] Average weekly wage data for 2011 is still preliminary.

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

2.286%, respectively. Based on an update period ended March, 2012, trued up through August 31, 2012, GMO is currently requesting an increase of $58.3 million in the revenue requirement in MPS rates, which amounts to a 10.9% increase and an increase of $25.2 million or a 14.6% increase in the L&P rates that is in addition to the 21% increase.

The increase in average weekly wages for counties in the MPS rate district is less than one-half of the increase in electric rates from 2007-2011 and less than one-third of the increase in rates if GMO received its requested 10.9% for the MPS rate district. The increase in average weekly wages in the L&P rate district is approximately one-third of the increase in electric rates from 2007-2011 and less than one-quarter of the increase in electric rates if GMO received its requested 14.6% for the L&P rate district. Furthermore, in the first quarter of 2012 the cost of living utility index[7] for Missouri was 103.1. This indicates that general utility expenses constitute a higher percentage of a Missouri resident's living expenses than the average U.S. resident. The U.S. average is an average of the participating urban areas in that quarter and is the "base" value set at 100 for comparison. Although average weekly wages are increasing the cost of living as reflected by the CPI is increasing, decreasing the positive impact of the increase in average weekly wages.

According to the Current Economic Conditions in the Eighth Federal Reserve District report from the Federal Reserve Bank of St. Louis,[8] Missouri's recovery has been slower compared to the nation in personal income and economic activity. Chart 3, illustrates this through a comparison of personal income between the United States and Missouri, based on data obtained from the Bureau of Economic Analysis.

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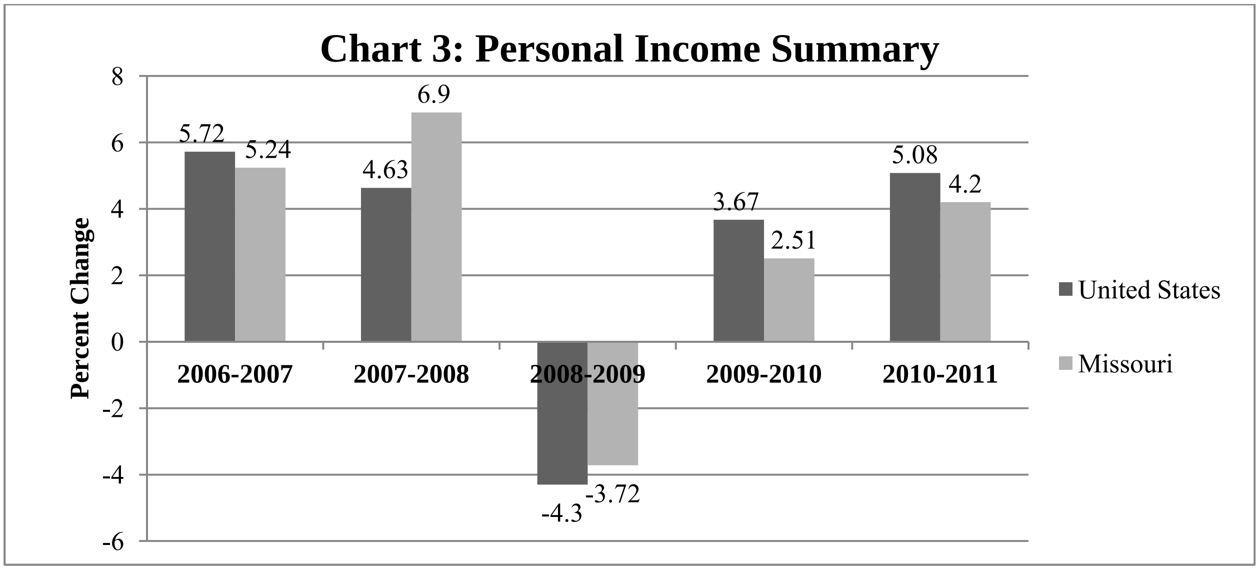
[7] Source: Missouri Economic Research and Information Center ("MERIC") and The Council for Community & Economic Research – 1st Quarter 2012. The cost of living composite index represents indices for grocery items, housing, utilities, transportation, health care and misc. services. The utility index includes electric, natural gas and telephone services.

[8] The Federal Reserve Bank of St. Louis' Current Economic Conditions in the Eighth Federal Reserve District, June, 2012 report included state and national level data as well as MSA level data for the St. Louis area. The only information used from the report was the national and state comparisons.



This data shows that Missouri experienced a percentage change of positive 4.2% in personal income, while the nation experienced a percentage change of positive 5.08% between 2010 and 2011.

The Federal Reserve Bank of St. Louis, using data from the Federal Reserve Bank of Philadelphia, also reported that Missouri's coincident index,[9] as of June 2012, is at 94.4% of its pre-recession level where the nation is at 101.2% of its pre-recession level. Missouri's lowest level of economic activity was reported at 91.9% of pre-recession levels while the U.S only dropped to 95.3% of its pre-recession level. Missouri also fell behind the nation in Gross Domestic Product[10] ("GDP") growth in 2010 and 2011, illustrated in Chart 4.

[9] The Federal Reserve Bank of Philadelphia's coincident index is a combination of payroll employment, wages, unemployment and hours of work to give a single measure of economic performance. Per the Federal Reserve Bank of St. Louis, "The Federal Reserve Bank of Philadelphia has significantly revised their national coincident economic activity index since our previous publication."

[10] Source: Bureau of Economic Analysis ("BEA")

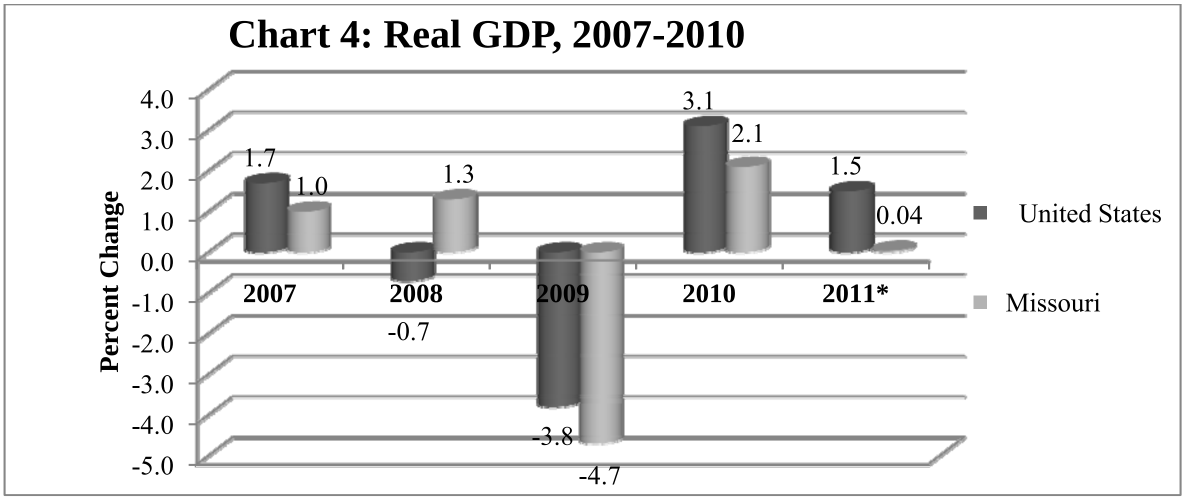


Chart 4, shows that Missouri's real GDP[11] only increased 0.04% in 2011, while that of the nation grew 1.5% in 2011 compared to the previous year. In 2010, Missouri's real GDP grew less than the nation's real GDP of 2.1% and 3.1%, respectfully. Growth in real GDP occurred in 2010 after Missouri's real GDP declined by 4.7% in 2009, compared to the nation's real GDP decline of 3.8%. Real GDP for the Kansas City MO-KS Metropolitan Statistical Area ("MSA"), which includes six counties in Kansas and nine counties in Missouri, [12] grew by 1.5% in 2010, which is also behind the U.S. Metropolitan portion's increase in real GDP of 2.5%.The personal income data, the coincident index data and the real GDP data suggests that Missouri is experiencing a slower recovery than the nation.

As explained below, the residents and businesses in the GMO service area are recovering from the longest and worst recession since the Great Depression[13] on lower than the national average weekly wage, lower than the national average per capita personal income and the unemployment rate[14] greatly increased since 2007. However, the state average for mortgage debt delinquency peaked in 2009 above the average for the GMO service area, as shown in Chart 5.

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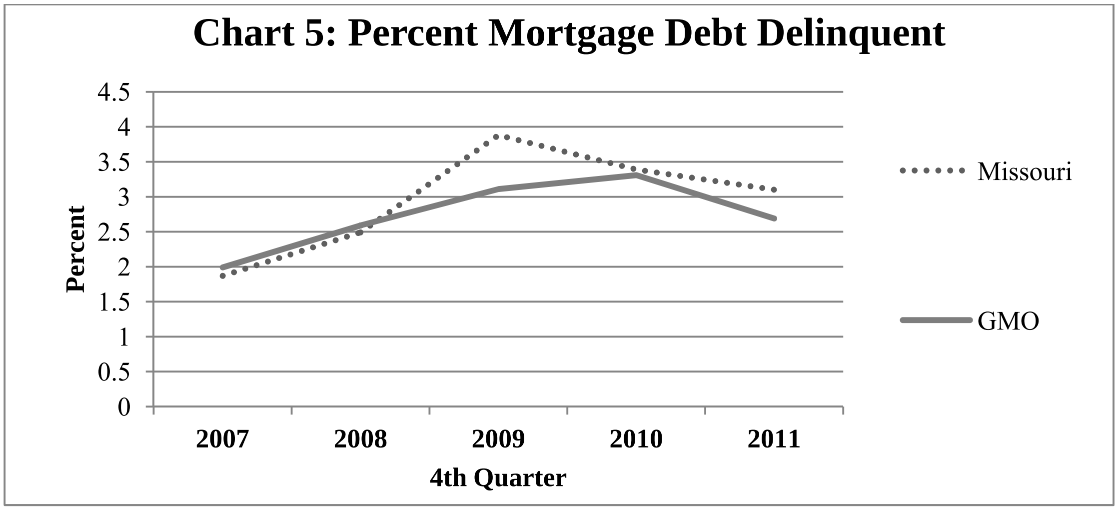
[11] Advance 2011 real GDP by State statistics and revised 1997-2010 statistics were released on June 5th, 2012 by the Bureau of Economic Analysis. Real GDP by Metropolitan Statistical Area ("MSA") for 2011 have not yet been released.

[12] Eight (Bates, Cass, Clay, Clinton, Platte, Jackson, Lafayette and Ray) of the nine Missouri counties in the Kansas City, MO-KS MSA are included in the GMO service area.

[13] The Economic Report of the President, Chapter 1, Federal Reserve Bank of St. Louis

[14] The GMO service area unemployment rate is calculated as a percentage of the total labor force.



Nevertheless, percent mortgage delinquency has increased between the fourth quarter of 2007 and the fourth quarter of 2011 for both the GMO service area and the state in general. The values in Chart 5 can be interpreted as percent of mortgage debt balance that is 90+ days delinquent.[15] Of the counties[16] in the GMO service area, Jackson County had the highest percent of mortgage debt balance 90+ days delinquent at 4.24% in 2011 up from 2.45% in 2007. Andrew County reported the lowest percent of mortgage delinquency at 1.05%.

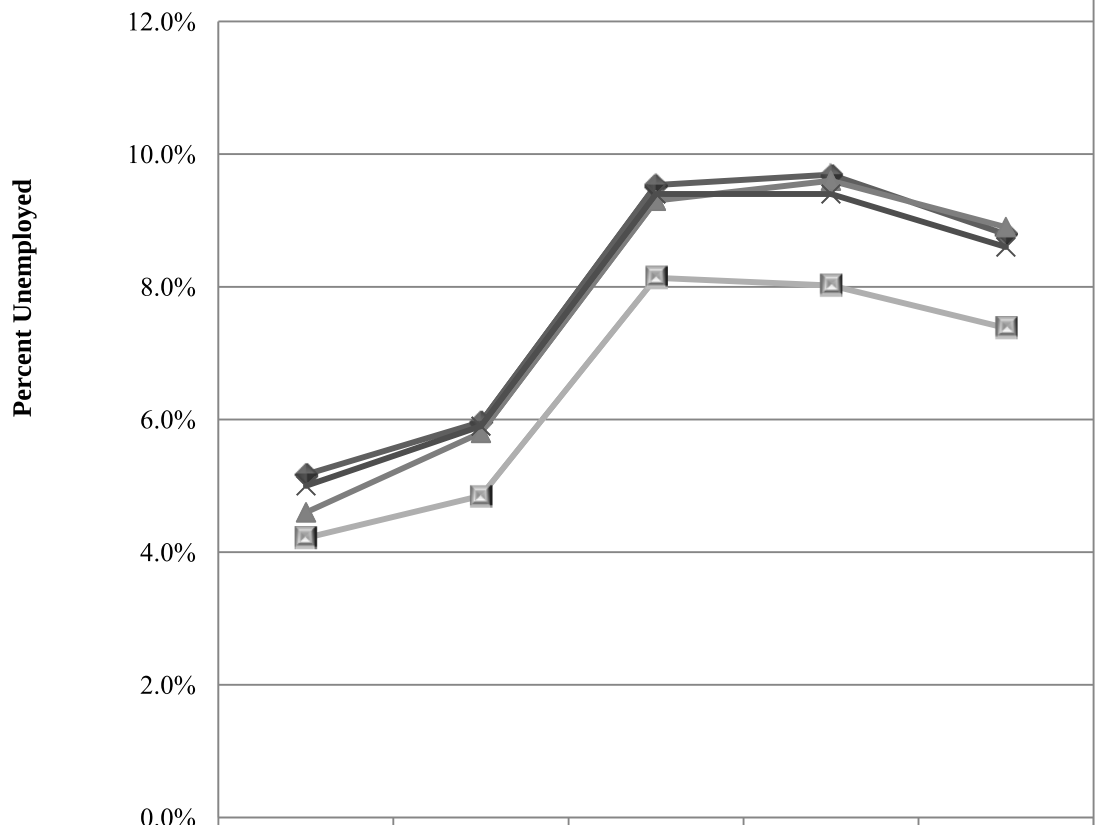
Counties in the MPS rate district experienced a slightly higher unemployment rate[17] than the nation and the state in 2007, 2008, 2009 and 2010, but a slightly lower unemployment rate than the nation in 2011. The L&P rate district has had a consistently lower unemployment rate than the state and the nation between 2007 and 2011, shown in Chart 6.

[15] Source: Federal Reserve Bank of New York, Consumer Credit Panel, 90+ days delinquent is considered seriously delinquent and in the foreclosure process.

[16] The Federal Reserve Bank of New York – Consumer Credit Panel, “only includes counties with an estimated population of at least 10,000 consumers with credit reports in the 4th quarter 2011.” This includes 77 of the 115 counties in Missouri, 4 of the 10 counties in the L&P rate district and 16 of the 24 counties in the MPS rate district. Due to the low number of counties represented in the L&P rate district, MPS and L&P are combined as GMO.

[17] Source: Bureau of Labor Statistics, Local Area Unemployment Statistics.

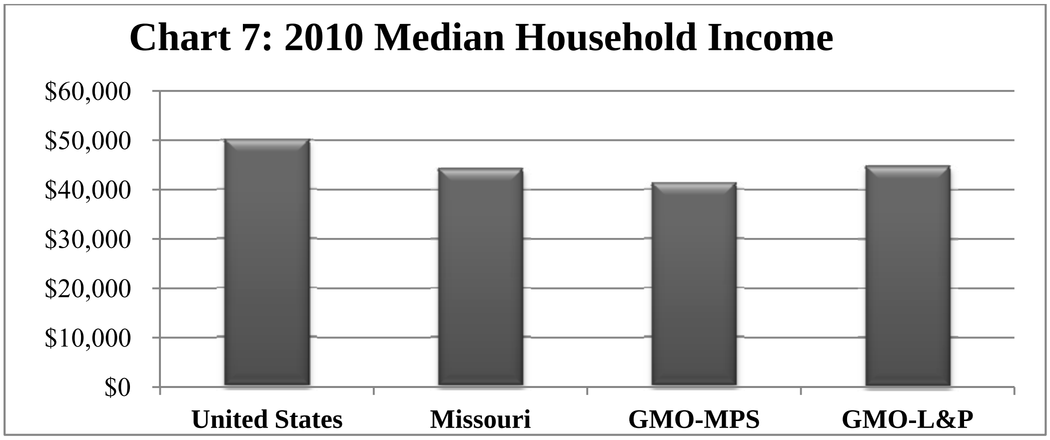
Chart 6: Comparison of Unemployment Rates



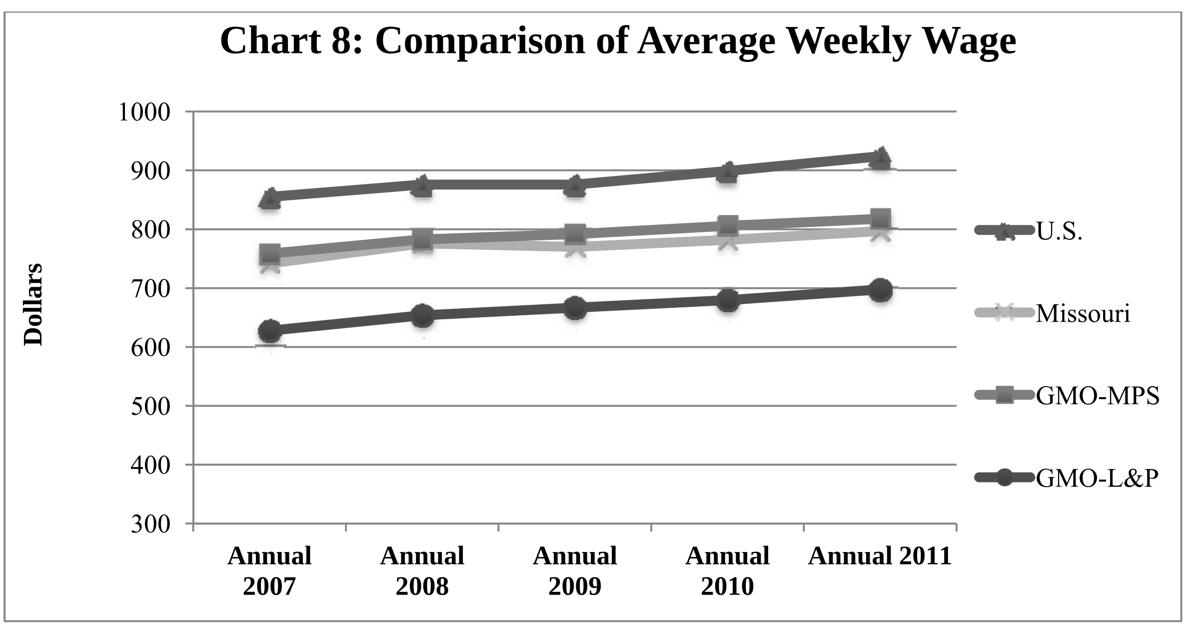
	2007	2008	2009	2010	2011
GMO-MPS	5.2%	6.0%	9.5%	9.7%	8.8%
GMO-L&P	4.2%	4.8%	8.1%	8.0%	7.4%
United States	4.6%	5.8%	9.3%	9.6%	8.9%
Missouri	5.0%	5.9%	9.4%	9.4%	8.6%

Although the unemployment rate seems to be decreasing in 2011 for the GMO service area, as a whole, all of the counties that GMO serves had higher unemployment rates in 2011 than in pre-recession 2007.

Chart 7, illustrates median household income based on data from the Missouri Economic Research and Information Center ("MERIC").



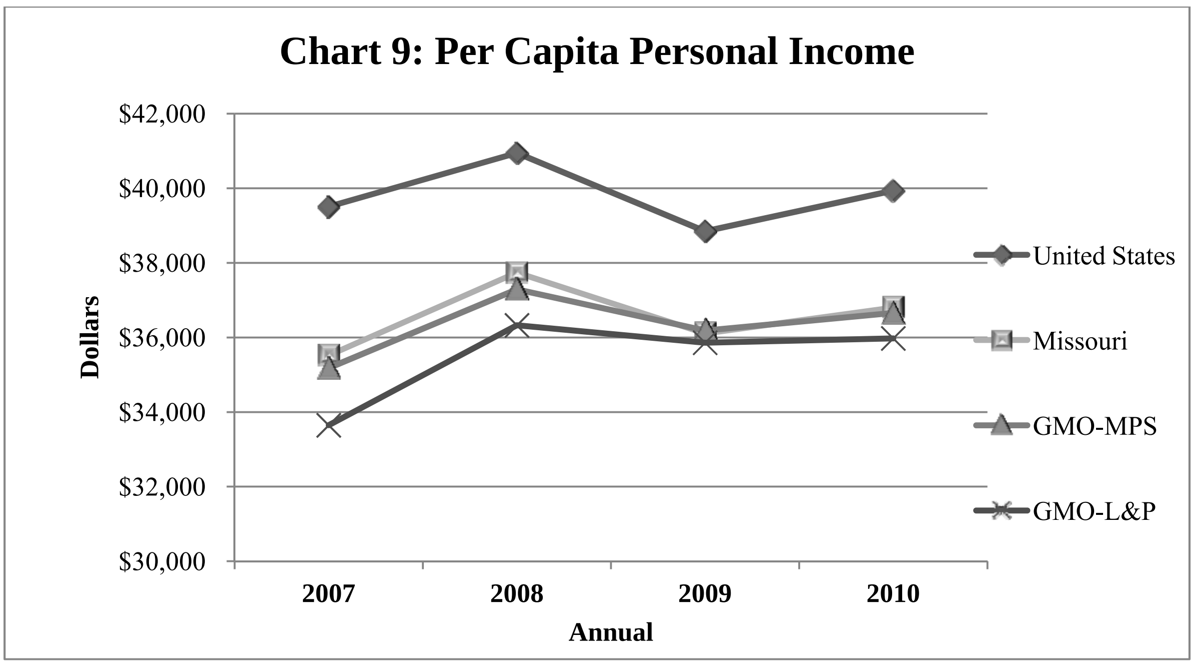
On average, the MPS rate district fell below the national and state median household income levels in 2010. However, the L&P rate district had a slightly higher median household income in 2010 than the state, but lower than the nation. The average weekly wage[18] in the MPS rate district fell below the national average, but is slightly higher than the state average, whereas the average weekly wage for the L&P rate district fell below both the state and the nation, shown in Chart 8.



[18] Source: Bureau of Labor Statistics: Quarterly Census of Employment and Wages, Average Weekly Wage 2007-2011. Per Bureau of Labor Statistics, "annual average weekly wage values are calculated by dividing total annual wages by the average of the twelve monthly employment levels and dividing the result by fifty-two."

In 2011, all of the counties served by GMO were below the national average weekly wage of $924. The only two counties in GMO's service area that reported a higher average weekly wage than the state average of $797 were Jackson County at $918 and Clay County at $849. The median average weekly wage in 2011, for MPS and L&P was $560 and $536, respectfully. This can be interpreted as the average weekly wage in 50% of the counties in the MPS and L&P rate districts are below $560 and $536, and 50% are above.

In 2010, the per capita personal income[19&20] level for the counties in the MPS rate district was $36,656 and the per capita personal income level for the counties in the L&P rate district was $35,973, which were both slightly lower than the state average of $36,799 and the national per capita personal income level of $39,937, shown in Chart 9.



Both of the per capita personal income levels for the MPS and L&P rate districts were higher in 2008 than in 2010. In 2011, Missouri reported per capita personal income at $38,248 which fell below the national per capita personal income level of $41,663. However, this was the first time both the state and the nation experienced a per capita personal income level that surpassed the 2008 levels by approximately 1.5%.

[19] Source: Bureau of Economic Analysis, Local Area Personal Income data for 2011 will not be available until November 26th, 2012.

[20] Per capita personal income is calculated as total personal income divided by total midyear population.

Furthermore, the Kansas City MO-KS MSA has a higher cost of living composite index[21&22] at 98.7 compared to Missouri's at 92.7. In fact, the Kansas City MO-KS MSA has the highest cost of living composite index in Missouri compared to other MSA's. Again, the values can be interpreted as a percentage of the U.S. average[23] which is the "base" value and comparison at 100.

The average cents per kWh, as reported by the EEI has the limitations stated above. The EEI average cents per kWh [24] for total retail for L&P (7.34¢) and MPS (9.31¢), for the 12 months ending December 31, 2011, is lower than the national average as calculated by EEI at 10.09¢ per kWh, as a whole, counties served by L&P and MPS have per capita personal income and average weekly wages below the national average and unemployment rates in 2011 were higher than 2007 pre-recession unemployment rates for all the counties that GMO provides service.

Comparing the average cents per kWh reported by EEI for total retail for MPS and L&P rate districts, indicates a 21% difference. In addition, EEI also reported the average cents per kWh for a MPS residential customer is 10.81¢ and 8.64¢ for a L&P customer, which is an approximately 20% difference. However, it is important to note that the average cents per kWh reported by EEI are not specific tariff rates paid by consumers and should not imply a 20% difference in residential rates or a 20% difference in an average monthly bill for a MPS and L&P residential customer. EEI does not describe how it calculates the average cost per kWh that it reports. Average cents per kWh can be calculated as total revenues collected by the utility divided by total kWh, which can include revenues from energy efficiency program charges, customer charges, demand charges, fuel adjustment charges or any other type of specialty program in addition to a customer's general energy rate. Each utility has different billing and rate structures.

Therefore, Staff compared an average monthly bill for a typical residential general use customer and for an average residential all-electric customer from MPS and L&P. For

[21] Source: Missouri Economic Research and Information Center (MERIC) and The Council for Community & Economic Research – 1st Quarter 2012.

[22] The cost of living composite index represents indices for grocery items, housing, utilities, transportation, health care and misc. services.

[23] The U.S. average is an average of the participating urban areas in that quarter.

[24] Source: EEI Typical Bill Rankings Report and Typical Bill/Average Rates Report, provided by KCPL in Data Request 241.1 in Case No. ER-2012-0174. Average cents per kWh for total retail and includes the subgroups of residential, commercial and industrial.

a residential general use customer, the average usage for winter months is 760 kWh and 1150 kWh for summer months.[25] For a residential all electric customer the average usage for winter months is 1340 kWh and 1430 kWh for summer months.[26] The analysis is shown in Table 2 and Table 3.[27]

Table 2: Comparison of GMO Residential Customers
760 kWh - Winter Usage, 1150 - Summer Usage

	MPS	L&P
Date of Current Rate	6/25/2011	6/25/2014
Average Monthly Bill	$104.47	$98.55
Difference		5.67%

Table 3: Comparison of GMO Residential All Electric Customers
1340 kWh - Winter Usage, 1430 - Summer Usage

	MPS	L&P
Date of Current Rate	6/25/2011	6/25/2014
Average Monthly Bill	$134.12	$123.52
Difference		7.9%

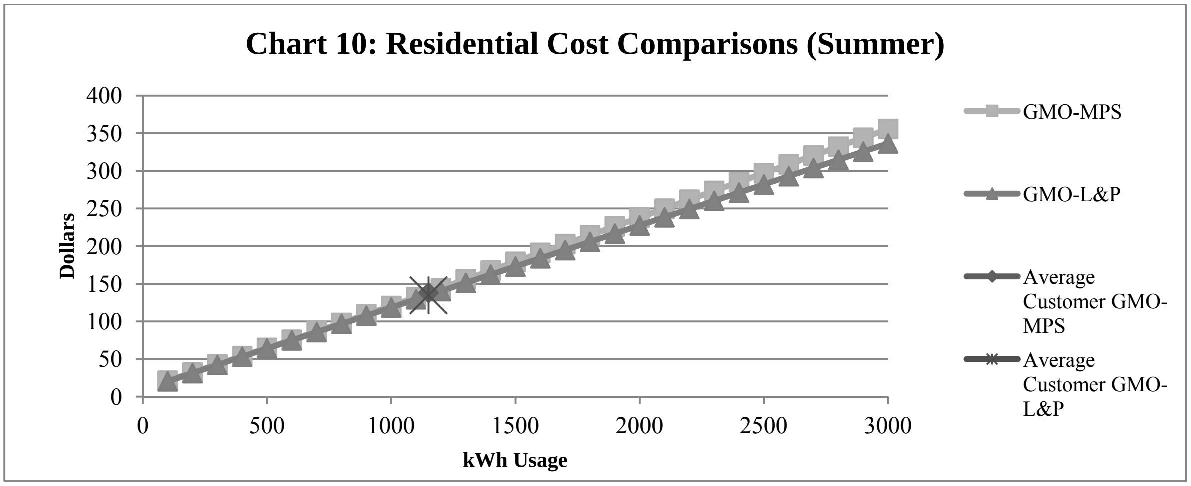
In Table 2, the difference between an average monthly bill for a MPS and a L&P residential general use customer is 5.67% and the difference in an average monthly bill for a residential all electric customer, shown in Table 3, is 7.9%. Both comparisons are less than the 20% difference in average cents per kWh for a residential customer that was in the EEI report.

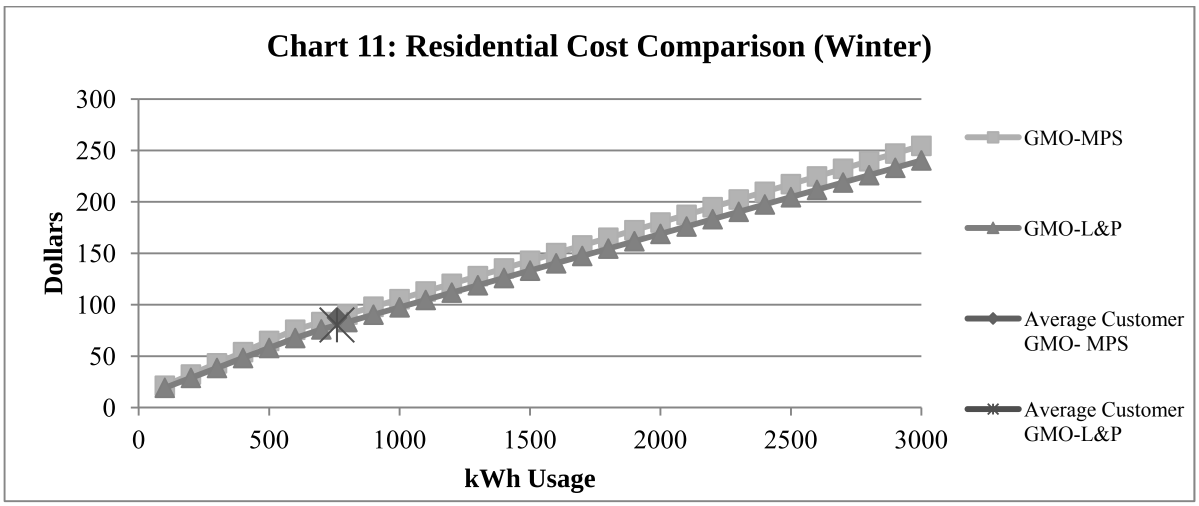
In addition, different levels of summer and winter usage were also compared using the respective rates for a residential general use customer. Chart 10, provides a comparison between L&P and MPS usage costs for summer kWh usage levels from 100 to 3,000 kWh and Chart 11 provides the same comparison for winter usage. The average summer usage of 1150 kWh and the average winter usage of 760 kWh are marked by a solid point or star on each chart.

[25] The average monthly usage for a typical residential customer is from the GMO press release in the minimum filing requirements for Case No. ER-2012-0175.

[26] Average usage for a residential all electric customer was calculated by dividing usage by the number of customers for the respective winter and summer months.

[27] The average monthly bill values in Table 2 and 3 do not include fuel adjustment charges.





Staff also compared an average monthly bill for a typical residential general use customer to other investor-owned utilities operating in Missouri based on the same average monthly usage, shown in Table 4.

Table 4: Comparison of Residential Customers
760 kWh - Winter Usage, 1150 - Summer Usage

	MPS	L&P	KCPL	Ameren Missouri	Empire
Date of Current Rate	6/25/2011	6/25/2014	5/4/2011	7/31/2011	6/15/2011
Average Monthly Bill	$104.47	$98.55	$97.27	$87.08	$106.29

According to the EEI report L&P reports the lowest average cents per kWh for a residential customer at 8.64¢, compared to all other Missouri investor-owned utilities. However, a typical L&P residential customer's average monthly bill is higher than an Ameren Missouri residential customer's bill and slightly higher than a Missouri KCPL residential customer's bill. From the EEI report, Ameren Missouri's average cents per kWh is 8.80¢ and KCPL's average cents per kWh for a Missouri residential customer is 9.90¢.

Again, average cents per kWh reported by EEI are not specific tariffed rates. Many utilities have different blocked rates based on usage, such as the first 650 kWh or the first 1000 kWh and different rates for summer and winter; therefore it is difficult to get an average energy rate per kWh.

Staff Expert/Witness: Robin Kliethermes

VI. Rate of Return

A. Introduction

An essential ingredient of the cost-of-service ratemaking formula is the rate of return ("ROR"), which is designed to provide a utility with a return of the costs required to secure debt and equity financing. This ROR is equal to the utility's weighted average cost of capital ("WACC"), which is calculated by multiplying each component ratio of the appropriate capital structure by its cost and then summing the results. While the proportion and cost of most components of the capital structure are a matter of record, the cost of common equity must be determined through expert analysis. Staff's expert financial analyst, David Murray, has determined GMO's cost of common equity by applying well-respected and widely-used methodologies to data derived from a carefully-assembled group of comparable companies. Staff then used that cost of common equity, net of any risk adjustments, together with other capital component information as of June 30, 2012, to calculate GMO's fair rate of return, as follows:

Capital Component	Percentage of Capital	Embedded Cost	Weighted Cost of Capital Using Common Equity Return of: **8.00%**	**8.50%**	**9.00%**
Common Stock Equity	51.82%	-----	4.15%	4.40%	4.66%
Preferred Stock	0.61%	4.291%	0.03%	0.03%	0.03%
Long-Term Debt	47.57%	6.247%	2.97%	2.97%	2.97%
Total	**100.00%**		**7.14%**	**7.40%**	**7.66%**

As contained in the above table, Staff estimates, based upon its expert analysis, a cost of common equity range of 8.00% to 9.00%, mid-point 8.50%, and an overall ROR of 7.14% to 7.66%, mid-point 7.40%. Staff recommends that the Commission authorize a return on common equity of 9.00% based on the high-end of its estimated cost of equity due to past concerns about Staff's estimates being too low. However Staff considers anywhere within its range of 8.00% to 9.00% to be reasonable but for purposes of its revenue requirement Staff used 9.00%. The details of Staff's analysis and recommendations are presented in attached Appendix 2, Schedules 1-23. 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.[28] In *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, the Court stated:[29]

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

Similarly, in the later of the two cases, *Federal Power Commission v. Hope Natural Gas Co.*, the Court stated:[30]

> '[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:

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[28] *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).

[29] 262 U.S. 679, 692-693, 43 S.Ct. 675, 679, 67 L.Ed. 1176.

[30] 320 U.S. 591, 603, 64 S.Ct. 281, 288, 88 L.Ed. 333, 345.

1. A return consistent with returns on 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.

The methodologies of financial analysis have advanced greatly since the *Bluefield* and *Hope* decisions.[31] 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;[32] 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

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

[32] 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.*

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 its recommended return on equity is higher than GMO's cost of equity.

C. Current Economic and Capital Market Conditions

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

1. Economic Conditions

The United States economy has been growing at a tepid pace since the most severe recession since the Great Depression. The pattern of this slow economic recovery has been much different than other past recoveries from severe recessions, in which the economy usually grew at a fairly rapid pace for a few years following the recession. This has investors, policy makers and academics concerned about the long-term prospects for not only U.S. growth, but for that of global economic growth. Most economists project domestic economic growth to be lower in the long-term as compared to the growth rates achieved during the post World War II era before the recent recession. Economists generally expect the long-term nominal Gross Domestic Product ("GDP") growth rate to be in the range of 4% to 5%.[33] These projected long-term nominal GDP growth rates generally are predicated on 2% expected inflation, as measured by the GDP price deflator.

[33] The Congressional Budget Office ("CBO"), *The Budget and Economic Outlook: Fiscal Years 2012-2022,* January 2012; Minutes from the Federal Open Market Committee's ("FOMC") meeting on April 24-25, 2010; First Quarter 2012 Survey of Professional Forecasters; Energy Information Administration's 2012 Annual Energy Outlook and The Livingston Survey, June 7, 2012.

The Federal Reserve Bank ("the Fed") continues to maintain the Fed Funds Rate at historically low levels between 0.00% and 0.25% (*see* Schedules 2-1 and 2-2). Additionally, the Fed decided in meetings held on June 19 and 20, 2012, to extend its bond buy-back program, "Operation Twist," through the end of the year. Through this program, the Fed hopes to continue to maintain, if not further reduce, already low long-term interest rates. Fed Chairman Ben Bernanke bluntly indicated, "if we don't see continued improvement in the labor market we'll be prepared to take additional steps." The Fed's announcement was accompanied by a revised outlook for lower economic growth in the near term as compared to previous estimates. The Fed now projects the economy will grow between 1.9% and 2.4% this year and less than 3% next year. The Fed also lowered its estimates for inflation to 1.2% to 1.7% for this year from its previous projection of 1.9% to 2.0% in April. The Fed continues to communicate to the markets that it will keep short-term interest rates low until late 2014.[34] Minutes since released from the June 19 and 20 meeting indicated: "Additional policy action could be warranted if the economic recovery were to lose momentum, if the downside risks to the forecast become sufficiently pronounced, or if inflation seemed likely to run persistently below the Committee's longer-run objective."[35]

Consequently, while there is much debate regarding the effect current monetary policy may have on inflation, it appears that the Fed's primary concern is still the lack of sustainable growth in the economy. Although there is also discussion of the possible impact monetary policy may have on inflation in the future, the market is not factoring in a high expected inflation rate in security prices. The 2012 monthly spread between 30-year Treasury Inflation Protected Securities ("TIPS") and non-inflation protected Treasury bonds implies investors are requiring an additional 2.25% to 2.40% return for potential inflation.[36]

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[34] Kristina Peterson and Jon Hilsenrath, "Fed Warns of Risk to Economy, Central Bank Extends Bid to Lower Long-Term Rates, Stands Poised to Do More," *Wall Street Journal,* June 21, 2012, p. A1 and A14.

[35] Kristina Peterson and Jon Hilsenrath, "Fed Weighs More Stimulus, Slow Recovery Has Central Bank on High Alert but Not Ready to Pull Trigger," *Wall Street Journal,* July 12, 2012, p. A1 and A2.

[36] http://research.stlouisfed.org/fred2/categories/22

2. <u>Capital Market Conditions</u>

a. Utility Debt Markets

Debt markets have been very attractive for utility companies in recent months. It has started to become fairly common for utilities to issue 10-year to 15-year bonds at coupons in the 3% range. For example, The Empire District Electric Company issued $88 million of 15-year secured debt at a coupon of 3.58% in April 2012. If one were to assume that the risk premium[37] required to invest in utility stocks rather than utility bonds was constant, then these lower utility debt yields directly translate into a lower required return on equity. In other words, a lower cost of debt is indicative of a lower cost of capital, all else being equal.

Unlike the short-term capital costs directly influenced by the Fed, long-term capital costs are typically market-based. Although long-term interest rates, as measured by 30-year Treasury bonds ("T-bonds"), increased to the 4% range during the November 2010 to July 2011 period, they have since decreased to the high 2% to 3% range for the period August 2011 through May 2012. (*See* Schedules 4-2 and 4-3.)

Long-term utility bond yields have also continued to more closely track the changes in the 30-year T-bond yields in the aftermath of the financial crisis of late 2008 and early 2009. Although the current spread between utility bond yields and 30-year Treasury yields is slightly above the average of 1.55% since 1980 (1.91%), the absolute yield on utility bonds recently fell below 5% for the first time during this prolonged period of low interest rates and slow economic growth. (*See* Schedules 4-1 and 4-3.)

Not only has the cost of investment-grade debt capital declined considerably, but it appears that the cost of non-investment grade debt has declined, as well (*see* Schedule 4-6). However, the spread between investment-grade and non-investment grade debt is higher than it was during the loose credit years during the middle of the previous decade (*see* Schedule 4-7).

b. Utility Equity Markets

For the twelve months ending December 31, 2011, the total return on the Dow Jones Industrial Average was 8.38%, the total return on the Standard & Poor’s 500 (“S&P 500”) was 2.11%, and the total return on the Edison Electric Institute ("EEI") Index of electric utilities

[37] Risk Premium in this context is defined as the excess required return to invest in a company’s equity rather than its debt.

was 19.99%. More specifically, on a non-market capitalization weighted basis, the total return for the twelve months ending December 31, 2011, was 22.30% for EEI "Regulated" electric utilities, 19.52% for EEI "Mostly Regulated" electric utilities and 21.36% for "Diversified" electric utilities.

Typically, utility indices tend to lag behind broader market indices that are increasing or decreasing. Regulated utilities are not expected to be as cyclical as the broader markets because of low demand elasticity; however, utilities with significant non-regulated operations are likely to be more affected by general economic trends. Although the returns of EEI's "Diversified" electric utilities and "Mostly Regulated" electric utilities had lagged that of "Regulated" Utilities in 2010, in 2011 the returns of all the categories were quite strong as compared to the broader markets. "Regulated" utilities' total returns in 2010 were 15.75%. Adding the "Regulated" utilities' returns for 2011 with those achieved in 2010, totals 38.05% over the last two years, a truly spectacular couple of years for electric utility stock returns. It appears that these strong returns have been driven largely by the continued decline in bond yields over the past year. This is highly consistent with investors' views that utility stocks compete with bond investments because they are largely considered to be bond surrogates/substitutes. In order for equilibrium to return to bond prices as they relate to utility stock prices, either bond prices would decrease (bond yields increase) and/or utility stock prices would increase. So far, it has been the latter. The increase in utility stock price valuations does not appear to be driven by higher growth expectations for the regulated utility sector. Staff's proxy group in this case contains eight companies Staff used in the prior Ameren Missouri rate case, Case No. ER-2010-0036. The average forward price-to-earnings ("p/e") ratio for these eight companies increased from 13.19x to 14.67x in just a little over a year. There are two primary drivers for higher p/e ratios, higher expected growth in earnings and/or a lower cost of equity, i.e. investors willing to pay a higher price per unit of earnings. In this case, it appears to be the latter because the projected 5-year earnings-per-share ("EPS") forecasted growth rates have actually declined since the last rate case. This is a clear indication that the cost of equity has declined since GMO's last rate case, which was filed 3 months prior to Ameren Missouri's last rate case. Another indication of the continued decrease in the cost of capital, especially for regulated electric utilities, is the fact that the electric utility industry is trading at a premium, i.e. higher p/e ratios, to that of the S&P 500. During a recent Society of Utility and Regulatory Analysts ("SURFA") conference Staff attended on April 26 and 27, 2012, Greg Gordon, CFA, Senior Managing Director and Partner with International Strategy and Investment, provided a presentation showing that regulated electric utilities' p/e ratios have been approximately 1.2x higher than that of the S&P 500. Higher p/e ratios are usually associated with higher growth companies. In the aggregate, the projected growth in EPS over the next 5-years for the S&P 500 is typically 10% or higher, whereas utilities' 5-year EPS growth forecasts are typically in the 5% to 6% range. Clearly, this means that investors are not paying a higher p/e for electric utility stocks for growth, but because of the low comparative returns offered by bonds. Utility stock returns are consistently highly correlated with bond returns. The current macroeconomic environment is clearly favorable to utilities in terms of a lower cost of capital for debt and equity instruments. Staff believes these lower capital costs should be shared with ratepayers through lower authorized returns on common equity ("ROEs").

In a recent Barron's 2012 Roundtable discussion, Bill Gross, founder and managing director of PIMCO, indicated the following about utility returns:

> They pay big dividends because they continually are granted a 10% return on equity by regulators in a world where returns are moving much lower. After earning 10% they can pay out 4% to 5% to investors.[38]

Consequently, it appears the capital market environment not only continues to support the ability to authorize ROEs below 10%, but it seems as if it expects them to be lowered considering the current capital and economic environment.

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

The following excerpt from GPE's Form 10-K filing with the United States Securities Exchange Commission ("SEC") for the year ended December 31, 2011, 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:

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[38] Lauren R. Rublin, "Listen Up, Class: Here's How to Profit," *Barron's Cover, January 16, 2012,* p. 11, http://online.barrons.com/article/SB50001424052748703535904577152932179268296.html#articleTabs_article%3D0

> • 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 (Receivables Company).
>
> • KCP&L Greater Missouri Operations Company (GMO) is an integrated, regulated electric utility that primarily 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 wholly owns MPS Merchant Services, Inc. (MPS Merchant), which has certain long-term natural gas contracts remaining from its former non-regulated trading operations.
>
> Great Plains Energy's sole reportable business segment is electric utility. For information regarding the revenues, income and assets attributable to the electric utility business segment, see Note 21 to the consolidated financial statements. Comparative financial information and discussion regarding the electric utility business segment can be found in Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A).
>
> The electric utility segment consists of KCP&L, a regulated utility, and GMO's regulated utility operations which include its Missouri Public Service and St. Joseph Light & Power (L&P) divisions. Electric utility serves approximately 823,000 customers located in western Missouri and eastern Kansas. Customers include approximately 725,000 residences, 96,000 commercial firms, and 2,600 industrials, municipalities and other electric utilities. Electric utility's retail revenues averaged approximately 90% of its total operating revenues over the last three years. Wholesale firm power, bulk power sales and miscellaneous electric revenues accounted for the remainder of electric utility's revenues. Electric utility is significantly impacted by seasonality with approximately one-third of its retail revenues recorded in the third quarter. Electric utility's total electric revenues were 100% of Great Plains Energy's revenues over the last three years. Electric utility's net income accounted for approximately 115%, 111% and 104% of Great Plains Energy's income from continuing operations in 2011, 2010 and 2009, respectively.

E. KCPL, GPE and GMO's Credit Ratings and Financing Activities

1. <u>Credit Ratings</u>

KCPL, GPE and GMO 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 interaction 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 'Baa3' and its S&P senior unsecured credit rating is 'BBB'. For comparison purposes, a Moody's 'Baa3' rating is considered to be equivalent to an S&P 'BBB-' rating.[39] Before GPE acquired Aquila, Inc. ("Aquila"), and its accompanying debt, its debt was considered to be non-investment grade. In order to allow for the debt associated with the entity now named GMO to be rated investment grade, which ultimately lowered GMO's cost of debt, GPE decided to guarantee GMO's debt. GPE also decided to guarantee GMO's commercial paper program in November 2011.

Although GPE is the entity that directly guarantees GMO's long-term and short-term debt, GPE's credit quality is made possible by its KCPL subsidiary as this is the only other asset GPE owns. 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 would have been allowed under traditional cost of service ratemaking.

Moody's rates GPE's senior unsecured debt equivalent to that of GMO's senior unsecured debt. S&P assigns GPE's senior unsecured debt a rating one notch lower than that of KCPL and GMO. Even though GPE has been considered to be more credit worthy than GMO, apparently S&P's methodology requires a one notch differential between the subsidiary and the parent company. 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 an April 27, 2012, S&P credit-rating report on GMO:

> Standard & Poor's Ratings Services bases its ratings on KCP&L Greater Missouri Operations Co. (GMO) on the consolidated credit profile of holding company Great Plains Energy Inc. This includes what we consider to be an "excellent" business risk profile and "aggressive" financial risk profile under our criteria. Great Plains is an integrated

[39] See p. 43 of Great Plain's Energy's 2011 SEC Form 10-K Filing.

> electric utility holding company that owns vertically integrated electric utilities GMO and Kansas City Power & Light Co. (KCP&L).
>
> The excellent business risk profiles for Great Plains, KCP&L, and GMO reflect their status as vertically integrated, fully regulated utilities serving roughly 825,000 customers in eastern Kansas and western Missouri. The utilities operate an approximately 6,600-megawatt (MW) generation fleet that is about 80% coal-fired. In its service territory, there have been gradual signs of economic improvement, with stronger industrial sales, but mixed unemployment rates; Kansas' is lower than the national average and Missouri's is slightly higher. Management has improved cash flow by effectively increasing revenues and cost recovery through mechanisms such as a fuel-adjustment clause and the allowance of additional accelerated depreciation. With a large coal concentration, timely recovery of environmental compliance costs, such as KCP&L's $615 million share of LaCygne environmental retrofit project, will be important. Because they are medium-size utilities with ownership in a single nuclear plant, Wolf Creek, the companies' business risk profiles are hindered somewhat by the probability that scrutiny and costs in the nuclear industry will increase because of the accident at Fukushima Daiichi in Japan.

Staff is not aware of any Moody's credit rating reports published specifically on GMO. However, as indicated before, Moody's does rate GMO's unsecured debt one notch below that of KCPL. It is Staff's understanding that Moody's rates GMO's unsecured debt based on the fact that GPE guarantees GMO's debt. Otherwise, GMO's stand-alone financial risk would not support an investment grade credit rating.

2. <u>Financing Activities</u>

Staff does not believe that GMO and KCPL have been financially managed as stand-alone companies. Subsequent to GPE's acquisition of the GMO assets, GPE has issued several different securities to either jointly fund capital needs for both KCPL and GMO or for purposes of loaning funds to GMO. GPE issued $287.5 million of equity units on May 12, 2009, which based on GPE's 2009 SEC Form 10-K Filing appears to have been pooled with several other financing sources, including KCPL's Series 2009A Mortgage Bonds in the amount of $400 million, and used for a variety of needs at both KCPL and GMO. On August 13, 2010, GPE issued $250 million of 3-year unsecured debt with a 2.75% coupon. Based on internal loan documents, the proceeds from this issuance were provided to GMO. On May 16, 2011, GPE issued $350 million of 10-year unsecured debt with a 4.85% coupon. Based on internal loan documents, the proceeds from this issuance were provided to GMO. On March 19, 2012, GPE issued $287.5 million of 10-year unsecured debt with a 5.292% coupon. Although this financing was tied to the equity units that were previously allocated to both KCPL and GMO, because the proceeds from this debt issuance were apparently used to partially refinance a GMO $500 million debt issuance that matured on July 2, 2012, this debt was assigned to GMO through an internal loan agreement.

KCPL has issued two debt financings subsequent to GPE's acquisition of the GMO assets. On March 24, 2009, KCPL issued $400 million of 10-year mortgage bonds at a coupon of 7.15%. On September 20, 2011, KCPL issued another $400 million of debt, but this time it was unsecured debt with a 30-year term at a coupon of 5.30%.

The weighted average coupon cost of debt assigned to GMO subsequent to its acquisition by GPE has been 4.402%, whereas the weighted average coupon cost of debt assigned to KCPL has been 6.23%. Although some of this difference has to do with the timing of the debt issuances, this wide difference in cost of debt seems inherently unfair to KCPL ratepayers considering they have provided the credit support for KCPL during the period of its comprehensive energy plan, which ultimately benefited GPE's credit quality and has made it possible to enhance GMO's credit quality.

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 Company's cost of common equity.

1. Capital Structure

Schedule 5 presents GPE's historical capital structures in dollar terms and percentage terms for the past five years. As can be derived from these historical capital structures, the current proposed ratemaking capital structure for GMO contains more equity than GPE's year-end equity ratios for the last four years. Staff understands that this is primarily due to the conversion of GPE's equity units into traditional common equity during the second quarter of 2012. In fact, it is for this reason that Staff proposes the use of financial data through June 30, 2012, for purposes of setting the allowed ROR in the general rate case. Before GPE issued the equity units, it typically had a common equity ratio close to 50%. Consequently, Staff has no reason at this time to dispute a ratemaking capital structure that has 52.475% equity ratio. However, being that there is a true-up scheduled for this proceeding, Staff can evaluate all known data through at least the true-up period to verify the reasonableness of the current proposed ratemaking capital structure.

Staff believes that the consolidated-basis capital structure of GMO's publicly-traded parent, GPE, as of June 30, 2012, is most appropriate for use as the rate making capital structure in this rate proceeding (*see* Schedule 6-1). Although this date is beyond the agreed upon updated test year of March 31, 2012, because of unique and significant financing activities occurring within GPE that were scheduled to be completed on or around June 30, 2012, this capital structure seems reasonable. This capital structure is appropriate because the risk embedded in GPE's capital structure affects GMO's credit rating and cost of debt. Staff's recommended GMO ratemaking capital structure consists of 51.82% common equity, 47.57% long-term debt, and 0.61% preferred stock.[40]

2. Embedded Cost of Debt and Preferred Stock

In GMO's most recent rate case, Case No. ER-2010-0356, Staff recommended using The Empire District Electric Company's embedded cost of debt as a proxy for GMO's cost of debt. However, after GPE issued debt between the updated test year of June 30, 2010, and the true-up period of December 31, 2010, KCPL and GMO decided to assign the GPE debt to GMO for purposes of updating the ROR recommendations. In response, Staff decided if the Commission accepted the inclusion of the GPE debt for purposes of the true-up, then the Commission should authorize a ROR for KCPL and GMO by applying GPE's consolidated adjusted cost of debt to both KCPL and GMO for purposes of the authorized ROR for each company. Although the Commission ultimately accepted the approach proposed by KCPL and GMO, which was to assign different costs of debt to KCPL and GMO based on debt either issued or assigned to each subsidiary, Staff believes that further GPE financing decisions since the last rate case (explained in Section E. 2. of this Report) provide additional support to apply GPE's adjusted consolidated cost of debt to both KCPL and GMO, especially when considering the fact that the Commission's Report and Order in Case No. EM-2007-0374 required KCPL ratepayers to be

[40] KCPL's response to Staff DR No. 194 and SEC 2009 10-K Filing.

held harmless from paying higher capital costs as result of financial effects of credit downgrades due to the acquisition of the GMO properties.

Although Staff has already explained GPE's, KCPL's and GMO's credit ratings and financing activities to some extent, for purposes of relating this information to Staff's position of applying GPE's consolidated cost of debt to KCPL and GMO for purposes of setting the allowed ROR, Staff will simplify and summarize the inherent inequity with the Company's proposed approach to the cost of debt. Before GPE acquired Aquila, Aquila's credit rating was considered a "junk" rating. This caused Aquila to incur higher costs of debt when it needed to issue debt for its capital needs. However, when GPE agreed to acquire Aquila, it provided a guarantee of Aquila's debt, which caused rating agencies to raise Aquila's ratings to investment grade status. This investment grade status allowed for lower debt costs for not only debt outstanding at Aquila at the time ($500 million of debt that had a coupon of 14.875% before the acquisition was reduced to 11.875% in consideration of the investment grade rating), but for new long-term and short-term debt issued on behalf of or by the entity now named GMO. GPE's ability to enhance GMO's credit rating was made possible by KCPL's credit profile as this formed the basis for GPE's investment grade credit rating. KCPL's rates were allowed to be set higher than normally would have been the case under traditional cost of service ratemaking during the period of the comprehensive energy plan, which covered the period in which capital expenditures were made for construction of Iatan II and environmental retrofits to Iatan I. KCPL was specifically allowed extra cash flow through increased rates during this period of construction to specifically target financial ratio benchmarks consistent with a 'BBB+' credit rating. However, during this period of higher capital expenditures, GPE decided to make a major acquisition, which placed further strain on its credit profile and the flexibility it had to provide cost effective capital for KCPL. This was magnified due to the financial crises that occurred in late 2008 and early 2009. In fact, GPE had so little financial flexibility during the financial crisis that it was forced to issue high cost equity units because it was on the verge of being downgraded to below investment grade status, which would have had a significant impact on the cost of capital for all of GPE's operations.

For the foregoing reasons, Staff believes it is important to scrutinize the corporate financing activities of GPE and its subsidiaries in order to ensure a reasonable cost of debt is charged to the utility operations and ultimately ratepayers through the allowed ROR. While

Staff has concerns about whether the cost of debt issued by GPE is consistent with the cost either KCPL or GMO could have achieved without being exposed to the business risk and lingering financial risk caused by Aquila's failed non-regulated investments, Staff's biggest concern is with how GPE is managing the tenor and type of debt offerings for GMO and KCPL. For example, on August 13, 2010, GPE issued $250 million of 3-year debt at a cost of 2.75%. GPE assigned this debt to GMO for purposes of its requested embedded cost of debt. However, only a year later, on September 20, 2011, KCPL issued $400 million of 30-year debt at a cost of 5.30%. Staff is not aware of why GPE would decide it was proper to issue 3-year debt for GMO, which carries a much lower cost, and 30-year debt for KCPL, which has a cost that is 2.55% higher. If KCPL had issued $400 million of debt at a 3-year tenor with a coupon similar to that of GPE (although KCPL would likely get a lower coupon because of its more favorable Moody's unsecured credit rating), then KCPL ratepayers would pay $10.2 million dollars less a year in interest expense. During the same year KCPL issued $400 million of 30-year notes, GPE issued $350 million of 10-year notes at a coupon of 4.85%. Although the embedded cost of the GPE notes ultimately ended up being higher due to interest rate swaps for hedging purposes, for some reason, GPE again decided to issue shorter-tenor notes for the financing it issued at the holding company compared to the notes issued at KCPL.

Consequently, not only is it likely that KCPL is paying a higher coupon on its debt due to its affiliation with GMO, but GPE is issuing longer-term debt at KCPL as compared to that issued for GMO, which comes at a higher cost. While it is difficult to ascertain exactly how much lower KCPL's debt costs could be absent this affiliation, Staff believes considering the fact that GPE introduced this circumstance through corporate acquisition activities, which causes uncertainty regarding higher capital costs KCPL ratepayers are paying, it is incumbent to error on the side of conservatism in estimating the cost of debt that should be allowed in the ROR.

Not only does Staff recommend a consolidated cost of debt be applied to both GMO and KCPL, but Staff also believes the cost of the debt issued by GPE should be adjusted downward to consider the fact that it is probable that KCPL and GMO could have received a lower coupon on this debt if it was issued with a 'BBB' unsecured debt rating, which is consistent with KCPL's current unsecured rating and the rating Aquila had before its non-regulated business failures caused its ratings to fall precipitously to as low as 'CCC+', which was only one category above default.

Staff made downward adjustments to the coupon rates of all three debt issuances GPE made subsequent to its purchase of the GMO assets. If the GMO assets had not been impacted by the Aquila legacy debt, then it is likely that GPE would not have had to provide a guarantee for debt associated with GMO's regulated utility operations because of its low business risk. In all likelihood, any subsequent unsecured debt could have been issued at a 'BBB' unsecured debt rating rather than the option GPE used, which was to issue holding company debt. For purposes of its adjustments, Staff simply applied the average 'BBB' utility debt yield for the months in which GPE issued the three notes in question. Staff matched the tenor of the actual debt with the tenor for the month in which the bond was issued. Staff adjusted the 2.75% coupon for the $250 million debt issued on August 13, 2010, to 2.00%. Staff adjusted the 4.85% coupon for the $350 million debt issued on May 16, 2011, to 4.70%. Staff adjusted the 5.292% coupon for the $287.5 million debt issued on March 19, 2012, to 4.25%.[41] After making all these adjustments and consolidating all GPE debt, this results in final consolidated cost of debt estimate of 6.247%. Staff recommends that this cost of debt be applied to GPE's consolidated capital structure for purposes of setting GMO's allowed ROR in this case (see Schedule 6-1).

3. <u>Cost of Common Equity</u>

Staff determined GMO's cost of common equity through a comparable company cost-of-equity analysis of a proxy group of 10 companies using the DCF method. Additionally, Staff used a CAPM analysis and a survey of other indicators as a check of the reasonableness of its recommendations.

a. The Proxy Group

First, Staff formed a group of comparable companies for the commensurate return analysis. Starting with 55 market-traded electric utilities, Staff applied a number of criteria to develop a proxy group comparable in risk to GMO's regulated electric utility operations (*see* Schedule 7). Staff decided to add one additional criterion in this case as compared to GMO's last rate case. Staff added a criterion to screen out companies that do not have an equivalent S&P business risk profile as GMO, which is currently 'Excellent.' Staff believes it was important to add this criterion to further screen utility companies that may have non-regulated operations that are impacting the parent company's business risk even though they

[41] Staff used BondsOnline for average utility bond yields for the appropriate tenor and rating.

were classified as "regulated" by EEI. For example, although EEI classifies Ameren as a "regulated" electric utility, many investment analysts, such as Goldman Sachs, consider Ameren to be a diversified company. Staff's criteria is as follows:

1. Classified as an electric utility by Value Line (55 companies);
2. Publicly-traded stock;
3. Followed by EEI and classified by EEI as a regulated electric utility (19 companies eliminated, 36 remaining);
4. Followed by AUS and reporting at least 70% of revenues from electric operations (11 companies eliminated, 25 remaining);
5. Ten years of Value Line historical growth data available (3 companies eliminated, 22 remaining);
6. No reduced dividend since 2009 (2 companies eliminated, 20 remaining);
7. Projected growth available from Value Line and Reuters (1 company eliminated, 19 remaining);
8. At least investment grade credit rating (3 companies eliminated, 16 remaining);
9. Company-owned generating assets (0 companies eliminated, 16 remaining);
10. Rated an 'Excellent' Business Risk Profile by S&P (4 companies eliminated, 12)
11. No significant merger or acquisition announced in last 3 years (2 companies eliminated, 10 remaining).

This final group of 10 publicly-traded electric utility companies ("the comparables") was used as a proxy group to estimate the cost of common equity for GMO's regulated electric utility operations. The comparables are listed on Schedule 8.

b. The Constant-growth DCF

Next, Staff calculated GMO's cost of common equity applying values derived from the proxy group to the constant-growth DCF model. The constant-growth DCF model is widely used by investors to evaluate stable-growth investment opportunities, such as regulated utility companies. The constant-growth version of the model is usually considered appropriate for mature industries such as the regulated utility industry.[42] 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 D_1/P_0, the expected next 12-months' dividend divided by current share price, is the dividend yield. Staff calculated the dividend yield for each of the comparable companies by dividing the a weighted average of the 2012 and 2013 Value Line projected dividend per share (*see* Schedule 11) by the monthly high/low average stock price for the three months ending May 31, 2012 (*see* Schedule 10).[43] Staff uses the above-described stock price because it reflects current market expectations. The projected average dividend yield for the ten comparable companies is 4.1%, unadjusted for quarterly compounding.

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 both 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

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[42] 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.

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

volatile.[44] Staff then analyzed the projected DPS, EPS and BVPS estimated by Value Line for each of the comparable companies over the next five years (*see* Schedule 9-3). While more stable than the historical growth rates, Staff still found a relatively wide dispersion in projected EPS growth (3.00% to 8.00%). Equity analysts' earnings estimates on *Reuters.com* also showed a wide dispersion of 3.00% to 6.96%. The average projected 5-year EPS annual compound growth rate estimates yielded a growth rate of 5.40%, which Staff believes is not sustainable (*see* Schedule 9-4, Column 6).

Due to the current volatility and wide dispersions present in Staff's analysis of historical and projected DPS, EPS, and BVPS, Staff only gave this data limited weight in estimating a reasonable growth rate for its single-stage DCF analysis. For reasons Staff will discuss in more detail below, use of equity analysts' forecasts of 5-year EPS growth is not reasonable in the context of estimating the cost of equity using a single-stage DCF methodology. However, if Staff uses growth rates consistent with these estimates in its constant-growth DCF, the cost of equity indication is approximately 9.10% to 9.60%.

Although use of equity analysts' 5-year EPS growth forecasts as a constant growth rate is easy and popular in utility ratemaking, investors do not assume their utility investments can grow at this rate into perpetuity when estimating a fair price to pay for utility stocks. Not only does practical investment analysis prove this wrong, but empirical evidence proves that EPS growth for the electric utility industry has never achieved these lofty growth rates over a long period. This was true even during the growth stage of the electric utility industry.

According to data published in the *2003 Mergent Public Utility and Transportation Manual,* electric utility growth rates have been approximately half of achieved GDP growth for the period 1947 through 1999.[45] As noted previously, long-term GDP growth is expected to be in the 4.0% to 5.0% range, suggesting that the expected long-term growth rate for electric utilities should be much lower than the projected 5-year EPS growth rates.

Staff also analyzed the growth of electric utilities identified by Value Line as *Central* region electric utilities over the period 1968 through 1999, a shorter, more recent period based on data from Value Line rather than Mergent (Staff will explain this analysis in more

[44] Schedule 9-1 depicts the annual compound growth rates for DPS, EPS and BVPS for each comparable company for the past ten years. Schedule 9-2 lists the annual compound growth rates for DPS, EPS and BVPS for each of the comparable companies for the past five years.

[45] 2003 Mergent *Public Utility &* Transportation *Manual*, p. a15 – a18.

detail when explaining its multi-stage DCF analysis). Staff's analysis of this data revealed that the actual realized growth of these electric utilities was less than *half* of GDP growth over this time period. In addition, this analysis also showed that during a period of much higher nominal GDP growth, the *Central* region electric utilities' EPS, DPS and BVPS grew in the range of 3.18% to 3.99% (*see* Schedules 14-1 through 14-4). Because the constant-growth DCF will only provide reliable results if the growth rate is within 1.0% to 2.0% of a sustainable long-term industry growth rate,[46] Staff decided its analysis of historical growth in the electric utility industry could only marginally support a more aggressive growth rate range of 5.0% to 5.5%. Staff emphasizes that it believes this growth rate is higher than what investors expect for the electric utility industry considering that it is higher than the expected long-term GDP growth of approximately 4.5%. Although there have been periods in which electric utility aggregate nominal growth has been higher than that of nominal GDP growth, this has not occurred for the last 20 years (*see* Schedule 12). On a per share basis, which is the focus of investors, electric utility growth has been much lower. Because a multi-stage DCF analysis allows investors to address non-constant growth expectations, Staff places primary weight on its multi-stage DCF analysis in this case.

Using the constant-growth DCF model and the inputs described above -- a projected dividend yield of 4.1% and a growth rate range of 5.0% to 5.5% -- a cost of common equity of 9.1% to 9.6% is implied (*see* Schedule 11).

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.[47] Staff believes this condition currently exists for the electric utility industry. Consequently, Staff has elected to use a multi-stage DCF method and will give this estimate primary weight in its estimated cost of equity for GMO.

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[46] Aswath Damodaran, *Investment Valuation: Tools and techniques for determining the value of any asset,* University Edition, John Wiley & Sons, Inc., 1996, p. 193.

[47] 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 in 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.[48]

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.[49] 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 cost of equity for the proxy group is approximately 7.80% to 8.60%, mid-point of 8.20%.

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

[48] 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.

[49] 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. In the last GMO rate case, the Commission indicated that Staff's growth rate estimates could not be confirmed by government or industry statistics.[50] Staff will provide the Commission with data from the government, industry and academics that supports the reasonableness, if not aggressiveness, of its estimated perpetual growth rate of 3.00% to 4.00%. Staff will first explain the methodology it used to determine that a 3.00% to 4.00% growth rate is a reasonable proxy for perpetual growth for its electric utility comparable group. Staff will then discuss the additional research it performed to conclude that it is not reasonable to assume electric utilities can grow at the same rate as nominal GDP in perpetuity.

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[50] *In the Matter of the Application of Kansas City Power & Light Company for Approval to Make Certain Changes in Its Charges for Electric Service to Continue the Implementation of Its Regulatory Plan,* Report and Order, Missouri Public Service Commission, File No. ER-2010-0355, April 12, 2011, p. 118.

The Financial Analysis Department has access to Value Line data on *Central* region electric utility companies dating back to 1968.[51] Although Staff has access to current electric utility financial data for all regions of the United States (*Central, East* and *West*), Staff's access to older data from the *East* and *West* regions is limited. 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.[52] Because 1968 is consistent 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 restructuring in anticipation of 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 14-1 through 14-4.

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[51] 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.

[52] 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 (Attachment D).

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%.

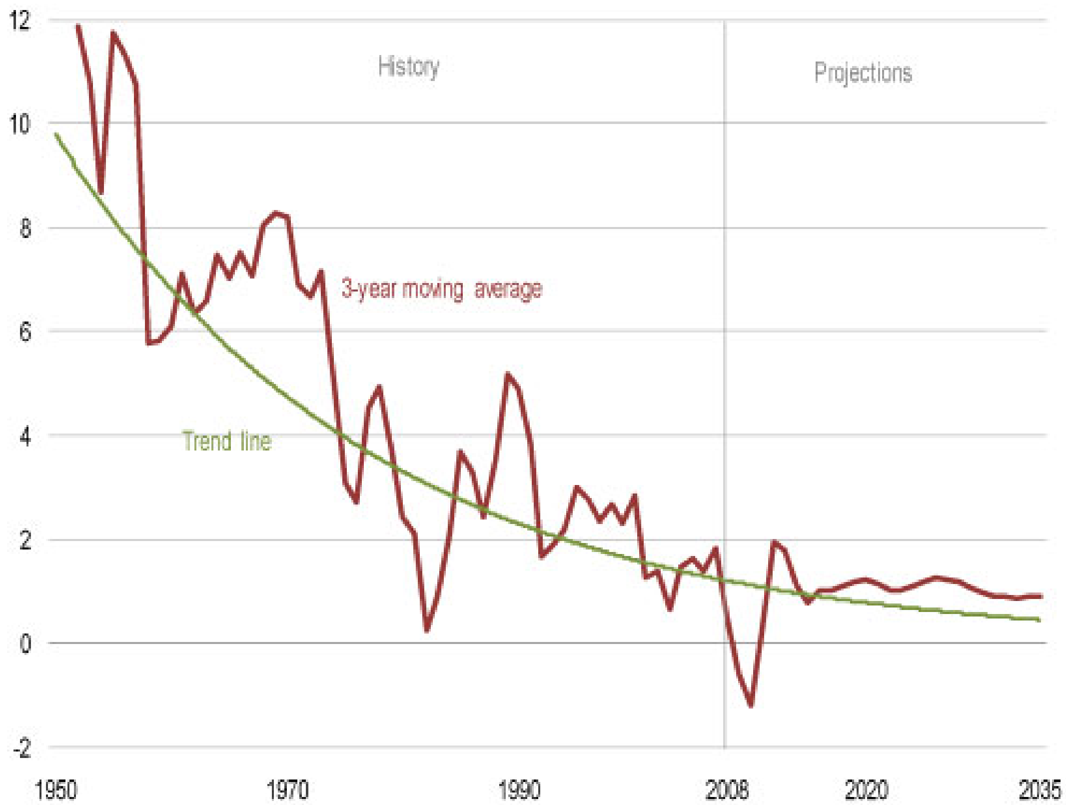
However, it is important to understand that these growth rates were achieved during a much more robust economic environment than the U.S. is expected to achieve in the foreseeable future. Also, it is interesting to note that the average growth rate for these electric utilities was less than 50% of GDP growth over the same period.

Also attached is Staff Schedule 15, which shows Staff's study of actual realized long-term growth of electric utility companies for the period 1947 through 1999 as published in the 2003 Mergent *Public Utility and Transportation Manual.* Although Staff has had problems replicating this data, Staff believes this information is still useful in evaluating the trends in growth rates for the electric utility industry, which shows a downward trend in growth over the last 30 years. This data also demonstrates that electric utility companies' EPS and DPS do not grow at the same rate as GDP over the long-term.

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

In the Commission's Report and Order in GMO's last rate case, Case No. ER-2010-0356, the Commission dismissed Staff's growth rates because they were not supported by government and industry data. As explained in the previous section of this report, Staff is using the same perpetual growth rates used in the last rate case based on data analyzed for the period 1968 through 1999. Staff considers this period to be logical considering it captured the last building cycle in the electric utility industry, which started in the 1970s, peaked in the 1980s and fell through the 1990s. In fact, growth rates for this period would likely be considered higher than those expected in the future due to the fact that this period encapsulated a period of higher demand for electricity as illustrated in the following Energy Information Administration ("EIA") chart provided in its 2011 Annual Energy Outlook:

Figure 59. U.S. elecricity demand growth 1950-2035
percent, 3-year moving average



Source: Energy Information Administration's 2011 Annual Energy Outlook

To meet this load growth, electric utilities made significant investments in generating capacity in the late 70's and early 80's.

In hopes of addressing the Commission's concerns about the lack of sufficient supporting government and industry data, Staff researched a variety of freely-available, web-based sources to determine if information is available that would allow for a broader and more extensive evaluation of actual realized growth in at least the broader utilities sector (i.e. electric, natural gas and water), if not specifically the electric utility industry. However, this information is not freely-available. Access to this information would require subscriptions to sources, such as Compustat, Factset, KnowledgeReuters and Ned Davis Research, which are often utilized by institutional investors. If the Commission would like Staff to perform a more comprehensive analysis, then Staff would need to further research the best sources to which to subscribe in order to obtain access to the relevant information at a reasonable cost. However, Staff was able to review and analyze an extensive amount of data comparing utility aggregate growth rates to per share growth rates that demonstrates that Staff's estimated perpetual growth rate of 3% to 4% is probably too high.

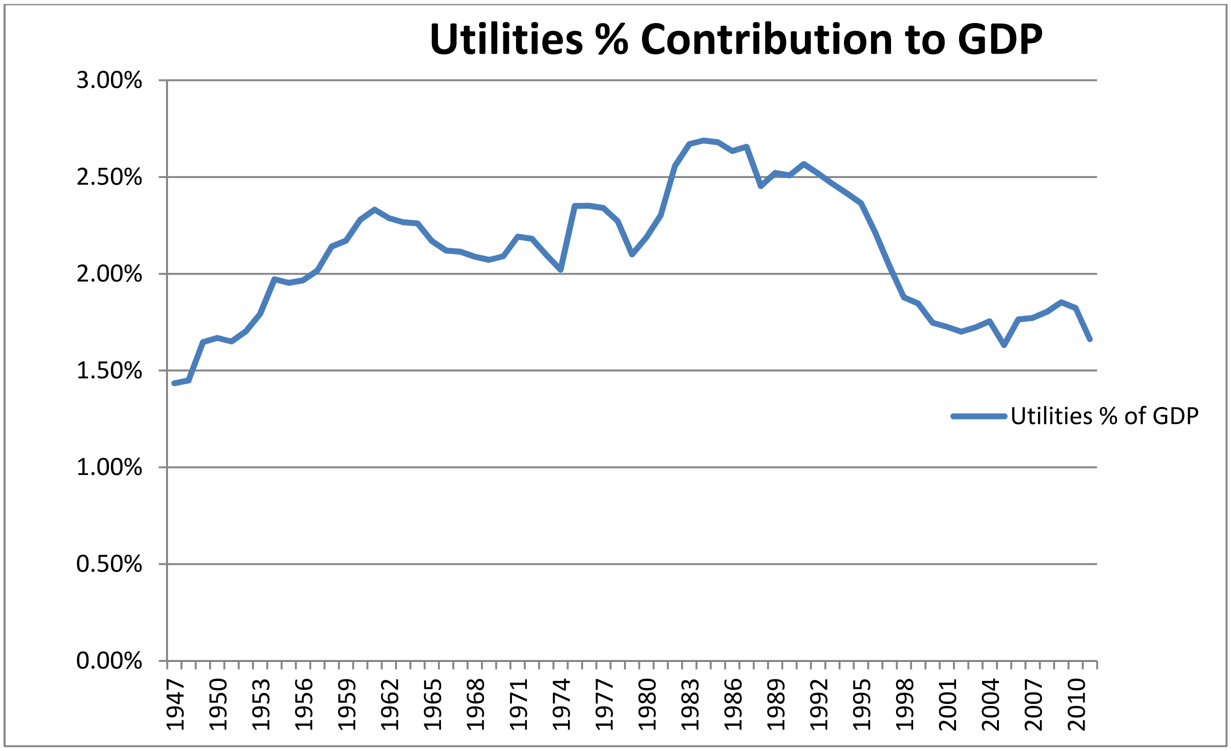
The other ROR witnesses in the last rate case used estimates of long-term nominal GDP growth rates for their perpetual growth rates.[53] Specifically, the Company witness provided his own projected nominal GDP growth rate by analyzing historical data, whereas the Missouri Industrial Energy Consumers, The Midwest Energy Users Association and United Stated Department of Energy witness relied on the *Blue Chip Economic Forecasts.* While there may be some logic for this approach for early to middle-stage companies, there is little logic for this approach for industries that are in the mature to declining stages of growth. Also, the use of nominal GDP growth does not take into consideration the fact that existing shareholders do not realize the aggregate growth of an industry due to the dilution caused by issuance of new equity.

Staff researched data provided by the Bureau of Economic Analysis ("BEA") on GDP growth by industry and by components. Although the use of projected aggregate GDP data is expedient and convenient, this comes at the expense of a reliable cost of equity estimate. Staff does not believe investors would sacrifice reliability for expediency when making investment decisions. Several industries contribute to the aggregate GDP of the U.S. economy. Currently, the BEA compiles data based on the North American Industry Classification System of the United States ("NAICS"). Although the NAICS definitions include more refined utility classifications, the BEA only reports data for the aggregate Utilities definition, which is assigned NAICS Code 22. Although this is an aggregate codification, Staff believes investors would rely on data specific to the utilities sector rather than that of the aggregate economy when estimating the potential growth of their utility investments. Better yet, Staff believes investors would drill down into the detail of the contribution of utilities' profits to GDP rather than that of *total value added* to GDP.

According to Staff's analysis of the utilities industry data available since 1947, as illustrated below and in Schedule 16, the utilities industry made up less than 2% of GDP until the middle 1950s and then gradually increased to just shy of 3% of GDP in the 1980s and 1990s.

[53] Nominal GDP includes economic growth caused by real factors, such as productivity improvements, technological advances and other factors that improve a country's overall standard of living, but it also includes expansion of the economy due solely to increases in the prices of goods and services, which is simply inflation.

However, since the late 1990s, utilities' contribution to GDP has declined to below 2% and has since leveled off.



Although it appears that utilities may contribute less to GDP going forward, if utilities continue to contribute the same percentage to GDP as they have for the last few years, then it is possible that the aggregate growth of *total value added* may be similar to that of aggregate GDP growth. It is extremely important to understand that this data represents *total value added* to GDP, not just aggregate earnings to shareholders or, more importantly, EPS and/or DPS, which is the primary focus of investors. Regardless, this data corroborates the data Staff provided in the last GMO rate case, which showed increases in EPS and DPS growth rates through the late 1980s and declining EPS and DPS growth rates from that point through at least 1999. Staff did not provide data for the period after 1999 because company-specific data lacked continuity due to restructurings, mergers and acquisitions and the Enron debacle. The GDP data for the period after 1999 shows the growth rate of at least *total value added* to GDP by utilities is not declining to the extent it had been for the previous decade. If utilities are to be able to continue to stop this decline, they will need to determine how to add value to an economy that is not nearly as energy-intensive as it once was and is in fact looking at ways to cut back on energy use.

Although the GDP data does show some relationship between aggregate GDP growth and utilities' contribution to aggregate GDP growth, it is interesting to note that the *total value added* from the utilities' sector grew faster than aggregate GDP for a period, but during its decline it grew at a rate slower than GDP on an aggregate basis. While Staff has not quantified the gross capital invested in the utility industry during the period of growth, it is generally recognized that the electric utility industry required significant capital investment in the late 1970s and early 1980s due to the construction of large generation facilities. Although the electric utility industry is currently in another construction cycle, it is not driven by demand growth, but by environmental requirements, transmission investments, and replacement of aging and/or polluting generating facilities. Because this construction cycle is not driven by growing demand, it would not appear that this growth could be sustainable, otherwise this investment would cause rates to spiral out of control, if allowed by commissions.

The *total value added* measurement of GDP includes increases to GDP caused by inflation. Because the period analyzed by Staff includes a high inflationary period during the late 1970s and early 1980s, it is misleading to assume utilities may be able to contribute as much to real GDP as it may to nominal GDP. Consequently, Staff also analyzed real GDP growth as compared to the utility industry's real growth for the period 1947 through 2011 (*see* Schedule 17). Staff's growth rate calculations are based on the same methodology Staff used to evaluate the long-term growth of the *Central* region electric utilities. For 10-year periods up to 1979, the utility industry's real growth rates were higher than that of GDP. However, the utility industry's 10-year real growth rates were much lower than real GDP 10-year growth rates during the 1980s. This is most likely due to the tremendous amount of capital invested in the electric utility industry during the building cycle that occurred during this period. Real utility growth grew at a higher rate than that of real GDP for a brief period through the early-to-mid 90s, but since this time the real growth rate of utilities has been lower than that of real GDP growth. This would seem to imply that the utility industry is possibly in a state of decline or at least in another building cycle. If the latter, then this may cause investors to project higher aggregate growth over the near-term, but because this construction cycle is not being driven by demand growth, it seems illogical that investors would expect a growth rate higher than that achieved during the last construction cycle.

The utility industry's contribution to GDP discussed above is based on the *value added,* both real and nominal, of the industry, which is the sum of compensation to employees, taxes on production and imports less subsidies, and gross operating surplus. Gross operating surplus includes consumption of fixed capital ("CFC"), proprietors' income, corporate profits, and business current transfer payments (net).[54] Although gross operating surplus could be used as a proxy for utilities' capital contribution to GDP, it seems the more relevant data would be that of corporate profits considering we are attempting to estimate the growth of shareholder value. Again, however, it should be noted that the corporate profit figure is an aggregate figure, which does not consider the dilution caused by the issuance of new equity. Although utility corporate profits would seem to be the most relevant data for the purposes of evaluating utility growth, unfortunately, the BEA website does not provide this data for the aggregate utility industry for years prior to 1998. However, the BEA website does provide this data for SIC code 49 for electric, gas and sanitary services. Although this code includes industries other than utilities, it is still more refined than that of aggregate corporate profits for all industries that contribute to GDP growth. As with utility industry's *total value added* contribution to GDP, corporate profits peaked in the 1980s and have since declined (*see* Schedule 18). Staff was surprised to find that growth in corporate profits for SIC code 49 was as high as 20% in the early 1980s. This seemed to contradict the much lower electric utility industry per share growth rates published in the 2003 Moody's Public Utility Manual. Additionally, the growth rates in utility value added to GDP were also higher than electric utility industry per share growth rates, although not as much as the corporate profit growth rates. Because Staff analyzed a proxy group of Value Line *Central* region electric utilities over this same period, Staff decided to compare these per share growth rates to corporate profit growth and utility value added growth (*see* Schedule 19). Although these per share growth rates were not as low those of the Moody's index, they were still much lower than the growth of corporate profits and utility value added. The fact that electric utilities had to issue equity to fund capital expenditures during this period probably explains the difference in these growth rates.

[54] http://www.bea.gov/glossary/glossary.cfm.

The issuance of additional equity creates a dilution of earnings to existing shareholders. Because the utility industry has historically had a high dividend payout ratio (DPS/EPS), anytime it needs to make large investments, it needs to issue new capital in the form of debt and equity. This can cause a vicious cycle for utility companies as described in *The Analysis and Use of Financial Statements,* 1998, by Gerald I. White, Ashwinpaul C. Sondhi and Dov Fried:

> Although this example may appear unrealistic, it is a reasonable description of the plight of public utility companies (gas, electric, water) in the United States. To attract investors, these firms historically paid out most of their earnings as dividends. To finance growth, they periodically sold additional common shares. As a result, EPS growth rates were low. These firms were trapped in a vicious cycle. If they reduced their dividend rates, their EPS growth rates would rise, and they might be considered growth companies rather than bond substitutes.

Staff tested this theory by analyzing the aggregate growth rates of its Value Line *Central* region electric utility proxy group for the same period in which per share growth rates were analyzed (1969 – 1998). Staff found that the aggregate growth of earnings, dividends and book value of this proxy group was extremely tightly correlated (99%) to that of the utility industry's contribution to GDP growth. In fact, this proved to be a much tighter correlation than that of utility corporate profits, which had a correlation of 72%. Although aggregate utility growth has been lower than GDP growth since the early 1990s, the aggregate proxy group financial growth for the period 1968 through 1999 was 97% correlated to overall GDP growth.

While Staff believes the above correlations are more than coincidence, if Staff had access to more historical data for not only the *Central* region electric utilities, but also the *East* and *West* region electric utilities, these correlations could be tested further to ensure consistent relationships over time and over regions. Because we are testing the hypothesis that electric utilities' growth would converge toward the United States' estimated GDP growth, it seems logical to test this across regions. Additionally, a key weakness in the data Staff analyzed is that it does not extend past 1998. Staff deemed this necessary due to changes in the industry due to restructuring. However, Staff did extend the termination year for the aggregate financial growth figures for the companies in its *Central* region proxy group that continued to exist through 2010. The correlations for the aggregate growth rates for the 5 remaining companies to that of the utility industry's contribution to GDP growth and to overall GDP growth were approximately 97% and 91%, respectively.

Although there have been some strong correlations between aggregate electric utility financial growth and utility and aggregate GDP growth rates, this has not translated into equivalent per share financial growth for the electric utility industry. This is extremely important to understand when estimating the cost of equity because this is what matters to investors and the analysts that advise them. Historical experience has shown the per share growth was approximately half of aggregate electric utility financial growth over the period analyzed (*see* Schedule 20). Consequently, even if the Commission accepts the hypotheses that electric utilities' growth may be dependent on aggregate GDP growth, historical financial evidence proves this does not translate into the same growth on a per share basis. Historical evidence indicates that these aggregate growth rates should be divided by two in order to consider the dilution experienced by electric utility shareholders. The resulting perpetual growth rate would be approximately 2% to 2.5%, which is lower than that which Staff used in its cost of equity estimate, but consistent with the perpetual growth rates used by equity analysts when valuing electric utility stocks.

Staff's research regarding the relation of GDP growth to that of utility industry growth caused it to discover several journal articles that addressed GDP growth as it relates to EPS and DPS growth of the S&P 500. In past rate cases, Staff has provided academic and logical support that suggests that long-term nominal GDP growth may make sense as a proxy for perpetual growth for a broader index, such as the S&P 500. However, this assumption may even be too aggressive for purposes of estimating returns for the S&P 500.

William J. Bernstein and Robert D. Arnott published an article, "Earnings Growth: The Two Percent Dilution," in the September/October 2003 edition of the *Financial Analysts Journal.* This article reviewed some of the key drivers behind the bull market in the 1990s. One such driver was an apparent belief that earnings could grow faster than the macroeconomy. The authors contend that earnings must actually grow slower than that of the economy because growth of existing enterprises contribute only partly to GDP growth; the role of entrepreneurial capitalism, the creation of new enterprises, is a key driver of GDP growth, yet it does not contribute to earnings and dividend growth of existing enterprises. The other main factor the authors attributed to actual realized growth being less than that of aggregate GDP growth is that new equity issuances almost always exceed stock buybacks by an average of 2% or more a year.

A key observation made by the authors that lends support for the notion that at least aggregate corporate earnings may be able to grow at the same rate as GDP growth is that for the period 1929 through 2000, trend growth for corporate profits and nominal GDP was nearly identical. However, as the authors state, the ability of earnings and dividends to grow at this same rate is only possible if no new enterprises are created and no new shares in existing enterprises are issued. The authors illustrate that these two factors caused the growth in DPS over the period 1900-2000 to be 2.7% lower than real GDP growth in the United States and 2.3% lower than real GDP for relatively stable countries throughout the world. Consequently, empirical evidence shows that per share growth will be less than GDP growth even for the broader markets. The findings from the Bernstein and Arnott article were largely confirmed in another subsequent article, "Economic Growth and Equity Investing," by Bradford Cornell, published in the January/February 2010 edition of the *Financial Analysts Journal.* Cornell studied United States stock market data for the period 1926-2008. This information showed an average rate of dilution from aggregate growth of approximately 2%. The author specifically states: "Therefore, to estimate the growth rate of earnings to which current investors have a claim, approximately 2% must be deducted from the growth rate of aggregate earnings."

Although not addressed in these articles, another reason why broader markets may not grow at the same rate as U.S. GDP growth is because of the globalization of many companies that are domiciled in the United States. According to Ned Davis Research, 52.6% of pretax profits for companies in the S&P 500 came from outside the U.S.[55] Consequently, the profits of these global companies should also be dependent on the economic growth of the other countries in which they operate.

The above-mentioned articles address the relation of GDP growth to that of broader stock market growth expectations, not specifically to expected growth for utilities. In the August 2011 edition of *Public Utilities Fortnightly* ("PUF"), Steven Kihm addressed this issue more fully in an article, "Rethinking ROE: Rational estimates lead to reasonable valuations."[56] Kihm specifically addresses the recent common practice in utility rate cases of estimating the cost of equity using the DCF and assuming that utility share prices can grow in perpetuity at the same

[55] "A Smarter Way to Invest Globally? Maybe it's time for world-stock funds, rather than ones that focus separately on the U.S. and Overseas," Javier Espinoza, *The Wall Street Journal,* C5 and C8, June 4, 2012

[56] "Rethinking ROE: Rational estimates lead to reasonable valuations," Steven Kihm, *Public Utilities Fortnightly,* August 2011, pp. 16-21.

rate of nominal GDP. Kihm specifically stated the following in regard to the interaction of GDP growth, DPS growth of the S&P 500, and DPS growth for the Moody's Electric Utility stock index:

> In the last half of the 20th century, nominal GDP grew about 8 percent per year. Dividends per share for the S&P 500 Index grew at only 6 percent per year. Dividends per share for Moody's Electric Utility stock index grew even more slowly at less than 4 percent per year. This suggests that utilities can be expected to grow not at the GDP growth rate, but at about half that rate on an annual basis.

Although Staff has drawn similar conclusions when analyzing long-term utility per share growth as compared to GDP growth, Staff notes that Kihm identified the same 2% dilution in S&P 500 DPS growth as discussed in the aforementioned financial literature. Staff verified this observation by analyzing data provided in the *Economic Report of the President (2012),* which provides earning and dividend information for the S&P 500 from 1947 through 2011. Schedule 21 clearly shows that actual realized EPS and DPS growth is less than that of nominal GDP. Again, considering the fact that, on average, companies in the S&P 500 retain far more earnings to pursue growth than utilities, no rational investor would expect utilities to grow in the long-term at a rate close to that of nominal GDP.

Kihm discusses one of the often-used explanations as to why GDP should be used as a proxy for long-term utility growth -- namely, that if utilities don't keep pace with economic growth, they will become a shrinking segment of the economy. Staff's analysis of the BEA data actually proves that this is in fact what has happened over the last 60 years. Over approximately the last 20 years, utilities' *total value added* as a percentage of GDP growth has been declining. Although it is hard to fathom that utilities will become obsolete, assuming utilities do not need to expand to meet additional load growth, it is logical to assume that utilities should not grow much faster than the rate of inflation in the long-term.

Kihm worked for more than 20 years as a member of the staff of the Public Service Commission of Wisconsin ("Wisconsin Commission"). He developed the staff's two-stage DCF model, which is still used by Wisconsin Commission staff. The Wisconsin Commission staff's DCF model uses the inflation rate for the perpetual growth rate for utilities.

In the PUF article, Kihm also discusses the impact of dilution on expected growth rates for utilities by comparing Southern Company's aggregate dividend growth rate and Southern Company per share dividend growth rate to that of GDP growth for the period 1995 to

2010. Southern Company's annual compound growth rate for *aggregate* dividends was 4.2%, while the annual compound growth rate for nominal GDP was 4.6% for this same period. However, after taking into consideration the additional common equity Southern Company issued over this period, the annual dividend compound growth rate was only 2.6% on a per share basis. Clearly this empirical evidence disproves the assumption that utilities could grow anywhere near the rate of GDP growth over the long-term.

A simple example using the earnings retention method of estimating sustainable growth rates illustrates the fallacy of assuming that utility per share growth rates can approach the level of aggregate GDP growth. The S&P 500 has historically earned ROEs in the 10% to 15% range with an average close to 12.50%.[57] For purposes of this example, we will assume that the S&P 500 will earn a 12.50% ROE in the long-run. Assuming the S&P 500 dividend payout ratio remains near the average of approximately 40% for the past decade, then this translates into 60% of earnings retained for reinvestment. At an expected 12.5% ROE (mid-point of the 10% to 15% range), this translates into a potential growth rate of 7.5% for the S&P 500. Now, assuming electric utilities should be allowed to earn an ROE similar to that of the S&P 500, which would be too high in Staff's opinion, since electric utilities typically maintain a dividend payout ratio of approximately 65%, this allows for a potential growth rate of 4.375%. Consequently, simple mathematics dictates that because electric utilities have higher payout ratios than the S&P 500, even if they earn a similar ROE, their per share growth would have to be lower than the S&P 500. Considering that the allowed ROEs have been in the 10% to 10.25% range, assuming electric utilities continue to pay out 65% of their earnings in dividends, this would translate into a growth rate of approximately 3.5%.

It is worth emphasizing that the articles Staff has reviewed explore the relationship of GDP growth to EPS and DPS for the broader markets, such as the S&P 500. This is consistent with most mainstream financial literature that suggests expected nominal GDP growth can be used as a proxy for perpetual growth for a broad index. However, Staff is not aware of any such literature that suggests this is appropriate for a mature, low-growth sector such as that of utilities. In fact, Staff has provided evidence in past cases that investment analysts do not make this assumption when estimating a fair price to pay for utility stocks.

[57] Timothy Vick, "Picking Stocks The Buffett Way: Understanding Return on Equity," American Association of Individual Investors, April 2001; Frank K. Reilly, "The Impact of Inflation on ROE, Growth and Stock Prices," Financial Services Review, 1997.

Kihm also provides an example of why current utility stock prices seem logical when using a more reasonable cost of equity estimate. In Kihm's example, he uses an 8% cost of equity to arrive at a price estimate of $50.62 for Consolidated Edison, which was within 4% of the stock price at the time (June 2011). Kihm's example can be taken one step further by performing a DCF valuation estimate using the same cost of equity and the assumption that utility dividends per share can grow at the same rate as GDP in the long-term. Consolidated Edison's annual dividend in 2011 was $2.40. If one assumes that this dividend can grow in perpetuity at a compound annual rate of 5% and the cost of equity is the same 8% used by Kihm, then this would translate into an intrinsic value of $84, 66% higher than its current trading price. However, if one assumes a much more reasonable dividend growth rate of approximately 3% with the same cost of equity, then the intrinsic value of the stock would be $49.44, which is close to Kihm's estimate.

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_______ [58] ** It is this clear-cut evidence that should be considered by the Commission when determining the reasonableness of certain projected growth rates for dividends in the long-run.

vi. Preference for GDP Growth

Although Staff is confident that investors do not expect 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 4.90% through 2022; EIA projects an annual

[58] KCPL's response to Staff Data Request No. 0209.

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compound growth rate of 4.4% for the period 2010 through 2035; The Survey of Professional Forecasters projects a 10-year annual compound growth rate in real GDP of 2.64%; The Livingston Survey projects an average annual compound growth rate of 2.7% over the next ten years and the FOMC projects a central tendency long-term real GDP growth of 2.3% to 2.6%. In each 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 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 in the range of 4.3% to 4.9%. If the Commission chooses to use a GDP growth rate to estimate the cost of equity, Staff recommends the Commission use the lower end of the range (4.3%) because of the amount of evidence that shows that rational investors would not expect utility per share figures to grow at the same rate as GDP. When using a 4.3% GDP growth rate in Staff's multi-stage DCF results in a cost of equity estimate of approximately 8.85%.

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 2010. For the risk-free rate (Rf), Staff used the average yield on 30-year U.S. Treasury bonds for the three-month period ending May 30, 2012; that figure was 3.13%. For Beta, Staff used Value Line's betas for the comparable companies (*see* Schedule 22). The average beta (β) for the proxy group was 0.69. For the market risk premium (Rm – Rf), Staff relied on risk premium estimates based on historical differences between earned returns on stocks and earned returns on bonds.[59] The first risk premium was based on the long-term, arithmetic average of historical return differences from 1926 to 2011, which was 5.70%. The second risk premium was based on the long-term, geometric average of historical return differences from 1926 to 2011, which was 4.10%.

Staff's CAPM is presented on Schedule 22. The results using the long-term arithmetic average risk premium and the long-term geometric risk premium are 7.06% and 5.96%, respectively. While the cost of equity indication using the geometric average risk premium is more than likely below equity discount rates used to value utility stocks, Staff believes the 7.06% cost of equity is quite probable considering the current low bond yield environment. It is generally recognized that the risk premium over Treasury yields is higher than historical averages due to the Fed's efforts to keep Treasury yields quite low. However, this increases the opportunity costs of not investing in utility bonds and stocks, which puts pressure on the prices of these alternative, low-risk investments.

[59] From Ibbotson Associates, Inc.'s *Stocks, Bonds, Bills, and Inflation: 2012 Yearbook.*

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[60] 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 great 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 months of March, April and May 2012, "A" rated 30-year utility bonds and "Baa" rated 30-year utility bonds had average yields of 4.92% and 5.52% respectively.[61] Adding a 3% risk premium, the "rule of thumb" indicates a cost of common equity between 7.92% and 8.92%. Adding a 4% risk premium, the "rule of thumb" indicates a cost of common equity between 8.52% and 9.52%.

b. Average Authorized Returns

In the past, the Commission has applied a test of reasonableness using the average authorized returns published by Regulatory Research Associates ("RRA") as a benchmark. According to RRA, the average authorized cost of common equity for electric utility companies for the first six months of 2012 was 10.36% based on 25 decisions (first quarter – 10.84% based on 12 decisions; second quarter – 9.92% based on 13 decisions). This increase from calendar-2011 was driven by several surcharge/rider generation cases in Virginia that incorporate ROE premiums. Virginia statutes authorize the State Corporation Commission to approve ROE premiums of up to 200 basis points for certain generation projects. Excluding these Virginia surcharge/rider generation cases from the data, the average authorized electric utility ROE was

[60] 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.

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

10.05% for the first six months of 2012. The average authorized cost of common equity for electric utility companies for 2011 was 10.22% based on 41 decisions (first quarter – 10.32% based on thirteen decisions; second quarter – 10.12% based on ten decisions; third quarter – 10.00% based on seven decisions; fourth quarter – 10.34% based on eleven decisions).

The average authorized ROR for electric utilities for the first six months of 2012 was 7.89% based on 23 decisions (first quarter – 8.00% based on 11 decisions; second quarter – 7.78% based on 12 decisions). The average authorized ROR for electric utilities in 2011 was 7.95% based on 41 decisions (first quarter – 8.12% based on 13 decisions; second quarter – 8.01% based on 10 decisions; third quarter – 8.09% based on 7 decisions; fourth quarter – 7.61% based on 11 decisions).

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

c. Equity Analysts

Past Commission decisions have expressed the view that the cost of equity used by equity analysts is not relevant to determining a reasonable cost of equity estimate in utility ratemaking proceedings. Although Staff respects the Commission's decisions based on the evidence the Commission reviewed in past rate cases, Staff believes it can provide further analysis and explanation that supports the relevance of these cost of equity estimates to the cost of capital determined in a utility rate proceeding.

First, it is important to consider the inherent contradiction caused by using equity analysts' 5-year EPS growth rate forecasts as the constant growth rate of dividends in the single-stage DCF, but ignoring the rest of the analysis performed by the equity analysts. It is naïve to assume that investors would simply take values from the internet without researching the supporting analysis when making investment decisions. While this assumption may allow for expediency in estimating the cost of equity, investors do not make investment decisions with expediency as a priority. Staff has reviewed numerous equity research reports and it has NEVER seen an analyst estimate a fair price for a utility stock by making this naïve assumption. If the equity analysts that provide professional investment advice based on in-depth analysis do not utilize their own growth rates in this manner, then it is completely illogical to make this assumption for purposes of estimating the cost of equity. If the cost of equity is not considered a fair return in terms of the *Hope* and *Bluefield* cases, then the time and effort devoted to rate-of-return testimony would be better spent on determining an appropriate margin over the cost of equity that would be fair in setting the allowed ROE.

Rate-of-return witnesses often cite various academic studies to support their position that investors naïvely assume that dividends can grow in perpetuity at the same rate as equity analysts' estimates of the 5-year annually compounded EPS growth rate. Although Staff believes the fact that the very equity analysts that provide these forecasts do not make this same assumption when valuing utility stocks disproves this conclusion, it is important to understand the true conclusion of some of these studies. One of the studies often cited to support the use of equity analysts' 5-year EPS growth rate forecasts in the DCF is that of Burton G. Malkiel and John G. Cragg, "Expectations and the Structure of Share Prices." The conclusion of this academic study was that equity analysts' expectations had a greater influence on stock prices compared to simple extrapolations of historical financial data. Staff believes this conclusion is logical considering the vast amounts of resources dedicated to the discipline of securities analysis. However, Staff is not sure how subsequent studies concluded that the results of this study somehow translated into a proof that investors use 5-year EPS forecasts as a constant growth rate in the single-stage DCF methodology. In fact, the Cragg and Malkiel did not even use the DCF valuation model when testing their hypothesis regarding the influence of analysts' projections on stock prices. It is more plausible to conclude that, because investors rely on equity analysts' expectations, they rely on their investment recommendations (e.g. buy, sell or hold). Equity analysts' investment recommendations are based on their assessment of the intrinsic value of a given stock. Analysts' methodologies for estimating a fair price varies, but most at least assess the current price-to-forward earnings ratios both on a consensus basis and on the analysts' own estimates. If the analyst believes the company can grow its earnings faster than the consensus and/or the company deserves a higher price-to-earnings ("p/e") ratio than the consensus, then the analyst will expect a higher return than the consensus. In Staff's experience, this is the primary purpose for providing both absolute EPS forecasts and EPS growth rate forecasts. It allows investors to estimate a potential justified p/e multiple.

Cragg and Malkiel specifically indicated the following in their study:

> We would not argue that these estimates necessarily give an accurate picture of general market expectations. It would, however, seem reasonable to suggest that they are representative of opinions of some of the largest professional investment institutions and that they may not be wholly unrepresentative of more general expectations. **Since investors consult professional investment institutions in forming their own expectations, individuals' expectations may be strongly influenced—and so reflect—those of their advisers.** That several of our participating firms find it worthwhile to publish these projections and provide them to their customers provides prima facie evidence that a certain segment of the market places some reliance on such information in forming its own expectations. Also, insofar as other security analysts and investors follow the same sorts of procedures as those used by our sample analysts in forming expectations, general investors' expectations would resemble those of the analysts. Consequently, these predictions may well serve as acceptable proxies for general expectations and surely seem worthy of detailed analysis. (emphasis added)

In past rate cases the Commission has dismissed evidence Staff presented regarding assumptions investment analysts use to estimate a fair price to pay for utility stocks. Considering the above information, in which the foundation for the study concludes that investors rely and depend on their investment advisors, and therefore, stock prices reflect these expectations, it would seem that the cost of equity assumptions used by these investment analysts are indeed reflected in share prices. To assume that investors utilize the information provided by equity analysts in a way that is wholly inconsistent with how the very analysts that provide them use them, is not supported by any evidence.

Equity analysts often use the dividend discount model ("DDM") to estimate a fair price to pay for the stock. The DDM is synonymous with the DCF in utility ratemaking settings. The DCF in utility ratemaking is simply solving for the required return/cost of equity variable. In valuation, the goal is to solve for the fair price of the stock. Consequently, if equity analysts are of value to their clients, then the stock prices will reflect their estimates of future dividends and the required return on these dividends. Consequently, if one accepts the studies that security analysts' expectations influence investors, which is the conclusion made by Malkiel and Cragg, then this means that stock prices reflect the cost of equity used by these very same analysts. Staff's experience has been that these equity discount rates are usually much lower than cost of equity estimates provided by ROR witnesses in utility rate cases. Staff has provided many examples in the last several rate cases that indicate equity analysts use equity discount rates in the 7% to 9% range when valuing utility stocks. However, this does not mean that these equity analysts expect commissions to allow an ROE equivalent to the market-implied cost of equity. If allowed ROEs were set equal to the cost of equity, this would cause downward pressure on the stock price of a company whose earnings rely primarily on the regulated utility operations. This is the case because utility stock prices currently reflect investors' expectations of regulators continuing to allow returns of close to 10%.

Considering the fact that the Cragg and Malkiel study is the foundation for other studies that are cited to support the use of 5-year EPS forecasts in the constant growth DCF, it is important to understand how at least one of the authors has estimated required returns on stocks in his past studies and how he estimates required returns currently. In his May 1979 study, "The Capital Formation Problem in the United States," Malkiel estimated the required returns on the Dow Jones Industrial Average by using Value Line growth rates for the first five years. This growth rate was then reduced over time to that of the expected real growth rate of the economy, which was 3.6% at the time.[62]

[62] The use of a real GDP growth rate for perpetual growth is consistent with Goldman Sachs' valuation approach discussed in the last Ameren Missouri rate case, Case No. ER-2011-0028. While the Commission interpreted this to mean that inflation needed to be added to the real GDP growth rate to make the analysis correct, Malkiel made it clear that he purposely chose real GDP as a perpetual growth rate, but also indicated an argument could be made to use nominal GDP.

In a recent January 5, 2012, editorial in the *Wall Street Journal,* "Where to Put Your Money in 2012," Burton G. Malkiel provided his opinion on the long-run return expectations for U.S. equities. Malkiel simplified his approach by simply indicating that earnings and dividends in the market have grown at an approximate 5% rate over the long run. He simply added this long-run growth rate to the current approximate 2% dividend yield on the U.S. stock market to arrive at a long-run return estimate of 7% for the U.S. stock market, which is very close to the 6.80% projected return on the S&P 500 estimated by professional forecasters in the First Quarter 2012 *Survey of Professional Forecasters*. If Malkiel believed investors projected returns based on 5-year EPS forecasts on the U.S. stock market, then he would have projected a long-run return of approximately 12.3% (2% dividend yield plus 10.3% 5-year EPS growth forecasts for the S&P 500). He did not. While Malkiel and Cragg's studies certainly concluded that security analysts' estimates have an impact on share prices, they did *not* conclude that investors would assume security analysts' 5-year EPS growth rate forecasts are a proxy for perpetual growth.

The focus on earnings growth rates is understandable considering that most security analysts' stock predictions are based on a multiple of p/e ratios, but security analysts provide this information to evaluate potential p/e ratios as they compare to consensus p/e ratios. The ability of the analyst to accurately project future earnings and justified p/e ratios will determine whether that analyst is successful. Consequently, the focus on analysts' EPS projections is understandable in this context.

H. Cost of Equity Compared to Returns on Equity

It would likely be of interest to the Commission that the aforementioned Kihm article is not necessarily advocating that the allowed ROE be set based on a utility company's cost of equity. While it is quite clear that Kihm believes the cost of equity for utilities is in the 7% to 8% range, he does not advocate that commissions set the allowed ROE at this lower level. Kihm is just pointing out that commissions "might be doing the right thing, but for the wrong reason." Kihm is simply trying to emphasize that allowed ROEs should not be assumed to be the cost of equity for purposes of making investment decisions or for purposes of valuing utility assets or securities. Staff has performed extensive discovery in past rate cases that provide assurance that utility companies are not confusing the allowed ROE with the cost of equity.

In fact, Staff discovered the valuation analyses GPE and Aquila performed on the current properties known as GMO, used a cost of equity much lower than the allowed ROE.[63]

It is also quite clear from Staff's analysis of equity analysts' reports that analysts do not expect commissions to set the authorized ROE equal to the cost of common equity. Most equity analysts use a cost of equity in the 7% to 8% range, yet when projecting cash flows generated by the utilities through ratemaking, they assume companies will be authorized an ROE of close to 10%. While the Staff does not believe the Commission should allow investors' expectations of the authorized ROE determine what is authorized in a rate case, Staff does recognize that investors have become accustomed to some margin over the cost of equity being allowed in rates. In fact, some would argue that because book ROEs of the S&P 500 (10% to 15% on average) tend to be higher than the market cost of equity, this may justify the decision to allow an ROE higher than the cost of equity. If the Commission accepts this premise, then the issue before it would be what margin is fair and reasonable for purposes of complying with *Hope* and *Bluefield.* This is a matter that could be explored further if the Commission accepts the notion that the cost of equity is lower than that which it chooses to authorize.

I. Demand-Side Investment Mechanism

As of the date Staff was preparing the ROR Section of this Staff Cost-of-Service Report, a stipulation and agreement had not been finalized in GMO's Missouri Energy Efficiency and Investment Act ("MEEIA") Application, File No. EO-2012-0009. Therefore, it would be improper and premature to discuss this in detail in context of the Staff's Cost-of- Service Report. However, as Staff indicated in its Rebuttal Testimony in that case, Staff believes the Demand Side Investment Mechanism ("DSIM"), regardless of the final details, reduces GMO's business risk. Unfortunately, it is very difficult to quantify in terms of basis points just how much the cost of equity may be reduced by the final mechanism. Most of the companies in Staff's proxy group already have demand side programs along with special recovery and incentive mechanisms to encourage these programs. Consequently, some of the impacts on the cost of equity of more favorable rate-making treatment for demand-side investments are already reflected in the stock prices of these companies. However, Staff believes the granting of the DSIM, coupled with the

[63] Staff Cost of Service Report in Case No. ER-2009-0089, p. 39-42.

current high valuations on electric utility stock prices, i.e. low costs of equity, should more than support a Commission decision to allow an ROE for GMO somewhere below 10%.

J. 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 its cost of capital. Using widely-accepted methods of financial analysis, Staff has developed a weighted average cost of capital for GMO in the range of 7.14% to 7.66% (*see* Schedule 23). This rate was calculated by applying an embedded cost of long-term debt of 6.247% and a cost of common equity range of 8.00% to 9.00% to a capital structure consisting of 51.82% common equity, 47.57% long-term debt, and 0.61% preferred stock. Because there appears to be some concern in setting an allowed return on equity based on the cost of equity, Staff recommends the Commission set the allowed ROE at 9.00% in this case. Although this is well-above what Staff believes the true cost of equity to be in the current capital market environment, this allowed ROE would balance the concern about the impact a lower allowed ROE would have 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

VII. Rate Base

A. Plant-in-Service and Accumulated Depreciation Reserve

Staff recommends plant-in-service ("plant") and accumulated depreciation reserve ("reserve") balances be based on actual booked amounts as of the Update Period, March 31, 2012, except as discussed in the Depreciation section of this Report.[64] This includes plant additions that have occurred since the test year ending September 30, 2011, 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 during the period of March 31, 2012, through August 31,

[64] See Cost of Service Report Section X – Depreciation sponsored by Arthur W. Rice.

2012, the True-up cut-off date. Staff will also make a true-up adjustment to update for depreciation reserve balances related to those additions. 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 for GMO for the period ending March 31, 2012, 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.

During the analysis of GMO's plant reserve balances, Staff found GMO had made adjustments to the reserve account balances for retirement work in progress (RWIP).[65] GMO removed the retired plant and related depreciation reserve from its plant and reserve account balances as of the retirement dates. However, as of March 31, 2012, GMO had not removed the related reserve for cost of removal and salvage. As a result, GMO's books overstate the reserve for this retired plant; and, therefore, Staff made an adjustment 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. Staff also made an adjustment to include amortization of intangible plant for assets that GMO has paid for the right to use or operate, but that GMO does not legally own. Accumulated amortization is recorded for these intangible assets on an individual basis, and amortization ceases when the book value reaches zero. The amortization rate was set for each account using the depreciation rate of assets with the same classification. For L&P Adjustments E-189.1 E-190.1 and for MPS Adjustments E-170.1, E-171.1, and E-172.2 reflect the amortization of Intangible Plant.

The following table identifies KCPL and GMO electric utility generation resources:

Load	**Unit**	**Year Completed**	**Estimated 2011 MW Capacity**	**Primary Fuel**
Base Load	Iatan No. 2	2010	465(a)	Coal
	Wolf Creek	1985	560(a)	Nuclear
	Iatan No. 1	1980	494(a)	Coal
	LaCygne No. 2	1977	341(a)	Coal
	LaCygne No. 1	1973	368(a)	Coal
	Hawthorn No. 5(b)	1969	563	Coal
	Montrose No. 3	1964	176	Coal
	Montrose No. 2	1960	164	Coal

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

	Montrose No. 1	1958	170	Coal
Peak Load	West Gardner Nos. 1-4	2003	310	Natural Gas
	Osawatomie	2003	75	Natural Gas
	Hawthorn No. 9	2000	130	Natural Gas
	Hawthorn No. 8	2000	77	Natural Gas
	Hawthorn No. 7	2000	77	Natural Gas
	Hawthorn No. 6	1997	136	Natural Gas
	Northeast Black Start Unit	1985	2	Oil
	Northeast Nos. 17-18	1977	110	Oil
	Northeast Nos. 13-14	1976	105	Oil
	Northeast Nos. 15-16	1975	96	Oil
	Northeast Nos. 11-12	1972	98	Oil
Wind	Spearville 2 Wind Energy Facility (c)	2010	4	Wind
	Spearville WindEnergy Facility (d)	2006	8	Wind
Total KCP&L			**4529**	
Load	**Unit**	**Year Completed**	**Estimated 2011 MW Capacity**	**Primary Fuel**
Base Load	Iatan No. 2	2010	153(a)	Coal
	Iatan No. 1	1980	127(a)	Coal
	Jeffrey energy Center Nos. 1, 2 and 3	1978, 1980, 1983	173(a)	Coal
	Sibley Nos. 1, 2 and 3	1960, 1962, 1969	466	Coal
	Lake Road Nos. 2 and 4	1957, 1967	125	Coal and Natural Gas
Peak Load	South Harper Nos. 1, 2 and 3	2005	314	Natural Gas
	Crossroads Energy Center	2002	297	Natural Gas
	Ralph Green No. 3	1981	71	Natural Gas
	Greenwood Nos. 1, 2, 3 and 4	1975-1979	255	Natural Gas/Oil
	Lake Road No. 5	1974	63	Natural Gas/Oil
	Lake Road Nos. 1 and 3	1951, 1962	33	Natural Gas/Oil
	Lake Road Nos. 6 and 7	1989, 1990	41	Oil
	Nevada	1974	21	Oil
Total GMO			**2139**	
Total Great Plains Energy			**6668**	

a. Share of a jointly owned unit.
b. The Hawthorn Generating Station returned to commercial operation in 2001 with a new boiler, air quality control equipment and an uprated turbine following a 1999 explosion.
c. The 48 MW Spearville 2 Wind Energy Facility's accredited capacity is 4 MW pursuant to SPP reliability standards.
d. The 100.5 MW Spearville Wind Energy Facility's accredited capacity is 8 MW pursuant to SPP reliability standards.

Source: GREAT PLAINS ENERGY INC. 10-K. February 25, 2011

Staff Expert/Witness: Patricia Gaskins

3. **Iatan Common Plant Transactions**

On March 9, 2012, in Case No. EO-2011-0334, KCPL filed an Application for (1) approval of the transfer of existing Common Facilities located at the Iatan Generating Station to the Kansas Electric Power Cooperative, Inc. (KEPCo) and the Missouri Joint Municipal Electric Utility Commission (MJMEUC); (2) approval of the transfer of interests in permits to other owners of the new Iatan Unit 2 electric generating facility (Unit 2); and (3) approval, if deemed necessary, for the sale of an interest in utility materials and supplies inventory to KEPCo and MJMEUC.

Also on March 9, 2012, in Case No. EO-2012-0015, KCPL, GMO, and The Empire District Electric Company (Empire) filed a Joint Application for the approval of (1) Iatan Unit 1 owners (KCPL, GMO, and Empire) to lease, and grant easements over, portions of the Initial Iatan Station Site to the Unit 2 owners (KCPL, GMO, MJMEUC, and KEPCo) covering Unit 2 and the Common Facilities, and (2) the leasing of the Nower Property (a tract of land adjacent to the Initial Iatan Station Site) by KCPL to the other Unit I and Unit 2 owners for the landfill portion of the Common Facilities.

In its June 20, 2012 Order Granting Application in Case No. EO-2012-0015, the Commission approved the Joint Application, but noted that its Order Granting Application does not determine any matter related to accounting or ratemaking in Case No. ER-2012-0174, Case No. ER-2012-0175, and the next general rate action of Empire. The Commission also issued an Order Granting Application in Case No. EO-2011-0334 on June 20, 2012.

The Staff has had discussions with KCPL as to how to treat these transactions in the current KCPL and GMO rate cases. Because the Commission's Orders approving these transactions became effective only recently, KCPL and GMO have not proposed any specific ratemaking methodology for these transactions as of the date of the Staff's direct filing. The Staff expects that it will have ongoing discussions with KCPL and GMO once Staff is aware of how KCPL and GMO propose to treat these transactions in the rate cases, and Staff will reflect the appropriate ratemaking treatment in its true up revenue requirement proposal in this case.

Staff Expert/Witness: Charles R. Hyneman

4. Crossroad Energy Center Valuation

Summary and Conclusion

Staff recommends the Commission include the Crossroads Energy Center generating station ("Crossroads") in GMO's rate base for MPS in this proceeding based on its decision in GMO's 2010 rate case, Case No. ER-2010-0356, to place this generating facility in GMO's rate base for MPS after certain parties, including Staff, opposed its inclusion in that rate base. Certain parties, including Staff, also contested the valuation of Crossroads in that case and the Commission adopted a valuation and a level of supporting operating costs 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 value of Crossroads to be $61.8 million on that date. Based on this $61.8 million plant value as of July 14, 2008, to reflect Crossroads in GMO's rate base for MPS depreciation for Crossroads accumulated since July 14, 2008, must also be reflected. As of March 31, 2012 that accumulated depreciation in the depreciation reserve account is $9,029,578. Staff has included Crossroads (Net Crossroads Plant) in GMO's rate base for total MPS at the March 31, 2012 update period, as follows:

	March 31, 2012
Plant in Service	**$62,337,897**
Accumulated Depreciation	**9,029,578**
Net Crossroads Plant	**$ 52,770,422**

When deciding whether to include Crossroads in GMO's rate base in GMO's 2010 rate case, the Commission considered together the value of Crossroads and the deferred income tax and transmission costs associated with Crossroads, all of which were contested amounts. Viewing these items together, not independently, the Commission decided the amount for the associated deferred income taxes was $15 million and that GMO's customers should not bear the transmission costs for transporting energy from Crossroads in Clarksdale, Mississippi to GMO's service territory.

Staff supports the Commission's decisions regarding Crossroads because:

1. Aquila was imprudent in 2004 in not retaining the ownership of the 600 megawatt Aries facility;
2. Aquila was imprudent in 2004 in not retaining the ownership of the Aries site which would have allowed expansion of additional combustion turbines;

3. Aquila was imprudent in not reacquiring Aries in 2006 for the capacity and the site;
4. The Aquila family of companies was imprudent when it sold combustion turbines already under its ownership in 2002 to 2006 to third party entities at deeply discounted prices rather than using them for MPS and L&P, and did not build capacity needed for MPS and L&P; and
5. Aquila was imprudent in not securing needed turbine capacity at a time of tremendous buying opportunities with the collapse of merchant power markets in 2002-- a buyers' market-- or installing turbine units in time for them to replace the 2005 end of the Aries purchased power agreement

All the actions above resulted in the imprudent planning for replacing the five year PPA for up to 500MW from Aries that expired in May 2005. Since Aquila's actions caused MPS and L&P to be short of capacity at various times during 2005 to now, none of the increased costs for Crossroads, including transmission costs, should be passed on to its customers in MPS or L&P.

Consistent with the Commission's decision in GMO's 2010 rate case regarding Crossroads, Staff has included the ordered level of deferred income taxes as an offset (reduction) to rate base valued at $14.8 million at March 31, 2012.

Also, consistent with the Commission's decision in the last case, Staff has excluded GMO's transmission costs associated with Crossroads. Staff made adjustment E 74.1 in its Staff Accounting Schedules for MPS to remove the test year level of transmission expenses.

Introduction

GMO owns four natural gas-fired combustion turbines at its Crossroads generating station located in Clarksdale, Mississippi, that have a combined capacity of approximately 300 megawatts.—Great Plains' 2011 annual report identifies the facility as 297 megawatts (page 23 2011 Annual Report). This Mississippi generating station is located over 9 hours and 525 miles from Kansas City, and was originally constructed by Aquila Merchant Services, a wholly-owned non-regulated affiliate of Aquila, in 2002 to generate electricity to be sold into the non-regulated market. Aquila never intended Crossroads to be part of its regulated operations in western Missouri. When the merchant power market collapsed in 2002 after the Enron bankruptcy, Aquila, and its affiliates, decided to exit their non-regulated businesses and concentrate on 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 strategic to Aquila's regulated operations. While Aquila Merchant sold other non-regulated assets, it found no buyers for Crossroads.

Great Plains acquired Aquila and its affiliates in July 2008. When it acquired Aquila it 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 time for Crossroads to be included in GMO's requested rate base for MPS in its September 5, 2008, rate case filing docketed as Case No. ER-2009-0090.

Staff did not include Crossroads in rate base for MPS in that rate case, which settled without resolution of the dispute relating to the Crossroads plant. In GMO's following 2010 rate case (ER-2010-0356), GMO again proposed inclusion of Crossroads in its rate base for MPS. Staff again did not, but as an alternative Staff also put in evidence supporting different values for Crossroads in the event the Commission decided to include Crossroads in MPS' rate base.

As an alternative to excluding Crossroads from MPS' rate base, Staff recommended that the Commission consider using the value of Crossroads on July 14, 2008, when Great Plains actually acquired Crossroads. Staff presented evidence of several actual transactions during 2004 to 2006 where third-parties acquired combustion turbines in arms-length transactions. The $61.8 million value the Commission found should be used for Crossroads in the 2010 rate case is the average of the per kilowatt values of two combustion turbine facilities Aquila Merchant sold to Union Electric Company d/b/a AmerenUE in 2006 that Staff introduced into evidence in that case. The following appears at page 100 of the Commission's May 4, 2011 Order in Case No. ER-2010-0356:

> The Commission rejects Staff's adjustment to disallow the recovery of Crossroads in the Company's cost of service and replace it with the cost of two "phantom turbines." 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.

Attached to this Report as Appendix 3, Schedule CGF- 13 are selected pages of the Commission's May 4, 2011 Order related to Crossroads.

In Case No. ER-2010-0356, GMO had requested Crossroads be put into rate base at the value on its books and records, but the Commission's value for placement of Crossroads in GMO's rate base was significantly reduced from that level.. In doing so, the Commission 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]

The valuation of Crossroads determined by the Commission in Case No. ER-2010-0356 of $61.8 million was based on several valuations of actual transactions made by third party non-affiliates for combustion turbines based on arms-length negotiations.

Staff has included Crossroads in GMO's rate base for total MPS at the end of the March 31, 2012, update period, with a comparison of that valuation to the December 31, 2010, valuation the Commission ordered in GMO's last rate case, as follows:

	March 31, 2012	Commission Order December 31, 2010
Plant in Service	**$62,337,897**	$61,764,000
Accumulated Depreciation	**9,029,578**	5,981,778
Net Crossroads Plant	**$ 52,770,422**	$55,782,222

Support for Crossroad Energy Center Valuations

In GMO's last rate case, Staff presented evidence to the Commission of the values of combustion turbines sold to non-affiliated third parties after arms-length negotiations. The Commission relied on two of those sales transactions—one for the sale of the Raccoon Creek Energy Center (Raccoon Creek) and the other for the sale of the Goose Creek Energy Center (Goose Creek)– to determine the appropriate valuation for Crossroads.

Aquila Merchant built Raccoon Creek and Goose Creek in Illinois in 2003. It installed four General Electric Model 7EAs (Model 7EAs), 75 megawatt combustion turbines, at Raccoon Creek (a combined capacity of 340 MW) and six 7EAs at Goose Creek (a combined capacity of 510 megawatts). Model 7EAs are also the type of combustion turbine installed at Crossroads. AmerenUE issued an RFP to acquire turbine capacity in the summer of 2005 to which Aquila responded in August 2005 offering to sell both Raccoon Creek and Goose Creek to AmerenUE for ** ________________ ** as shown by the excerpt from GMO's response to Data Request No. 464 in Case ER-2005-0436 that follows:

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>
> [source: Data Request No. 464 in Case ER-2005-0436 Appendix 3 Schedule CGF- 14]

On December 16, 2005, GMO and AmerenUE entered into an asset purchase and sale agreement for the sale of Raccoon Creek and Goose Creek which closed in early 2006. The final sale price was $175 million and included all the generating equipment, substation and transmission costs. Since the total capacity of these two generating stations is 850 megawatts, the resulting installed capacity cost was $205.88 per kilowatt ($175 million divided by 850,000 kilowatts) [source: Aquila's SEC Form 8-K filed December 16, 2006].

Based on Aquila's initial offer the installed capacity cost would have been between ** ____ ________ **. Because the merchant business was distressed when this transaction was negotiated and closed, Aquila incurred pre-tax non-cash impairment charges of approximately $65.9 million for Raccoon Creek and $93.6 million for Goose Creek, or a total after-tax loss of $99.7 million ($58.5 million and $41.2 million) [source: Aquila's SEC Form 8-K filed December 16, 2006].

Raccoon Creek and Goose Creek were installed in 2003 and are currently are part of Ameren Missouri's generation fleet used to provide electric service to its Missouri customers.

Until after Great Plains acquired it, Aquila made no attempt to include either Raccoon Creek or Goose Creek in its regulated generation fleet. It indicated that it did not because they were located in Illinois and there was not a sufficient transmission path to get the electricity from them to MPS and L&P in western Missouri.

The $205 per kilowatt installed costs for Raccoon Creek and Goose Creek AmerenUE paid in 2006 are lower than the $427 per kilowatt installed costs of Crossroads as of the December 31, 2010, true-up date in GMO's last rate case based on the Commission's Order at page 80.

For comparison purposes, the three combustion turbines GMO installed in 2005 at South Harper were constructed and placed into service for $382 per kilowatt based on the December 31, 2010 true-up values identified at page 80 of the Commission's Order in GMO's last rate case.

Great Plains Valuation in Security Exchange Commission Filing

Great Plains and Aquila first publically disclosed an objective "fair market valuation" of $51.6 million for Crossroads in February to May 2007. Great Plains and Aquila again released this valuation to the public on at least three occasions from May 2007 to August 2007 in joint proxy statements and amendments Great Plains and Aquila filed with the SEC. That "fair market valuation" was Great Plains' estimate that it would receive $51.6 million in proceeds from the sale of Crossroads to an unrelated party in the then current market place. The following is a quote from Great Plains' and Aquila's joint proxy statement and amendments:

> D - The pro forma adjustment represents the adjustment of the estimated fair value of certain Adjusted Aquila non-regulated tangible assets and reduction of depreciation expense associated with the decreased fair value. The adjustment was determined based on Great Plains Energy's estimates of fair value based on estimates of proceeds from sale of units to an unrelated party of similar capacity in the current market place. The preliminary internal analysis indicated a fair value estimate of Aquila's non-regulated Crossroads power generating facility of approximately $51.6 million. This analysis is significantly affected by assumptions regarding the current market for sales of units of similar capacity. The $66.3 million adjustment reflects the difference between the fair value of the combustion turbines at $51.6 million and the $117.9 million book value of the facility at March 31, 2007.

> Great Plains Energy management believes this to be an appropriate estimate of the fair value of the facility. The adjusted value will be depreciated over the estimated remaining useful lives of the underlying assets and could be materially affected by changes in fair value prior to the closing of the merger. An additional change in the fair value of the facility of $15 million would result in an additional change to annual depreciation expense of approximately $0.5 million.
>
> [Great Plains Energy & Aquila Joint Proxy Statement/Prospectus the SEC on May 8, 2007, page 175]

Aquila, the owner of Crossroads in 2007, also stated that the "fair market value" of Crossroads was $51.6 million since it was party to the Joint Proxy Statement/Prospectus filed with the SEC in May 2007.

GENERAL ELECTRIC MODEL 7 EAS

In addition to the per kilowatt values from the sale of Raccoon Creek and Goose Creek, and Great Plains' and Aquila's SEC "fair market value" disclosure for Crossroads, in GMO's last rate case, where the Commission valued Crossroads for ratemaking purposes, Staff also introduced into evidence values from other combustion turbine negotiations and sales that support the Commission's rate base valuation of Crossroads.

In addition to the ten Model 7EAs at Raccoon Creek and Goose Creek sold to AmerenUE in 2006, Aquila Merchant earlier sold three Model 7 EAs to two non-affiliates after the 2002 energy market collapse and the decline of the turbine market. Aquila Merchant sold two Model 7EAs turbines to a utility in Beatrice, Nebraska, and a third to a utility in Colorado (Response to Data Request No. 43 in Case No. EO-2005-0156).

The two Nebraska turbines sold for ** ____ ** million, or ** ____ ** million each, and the third Colorado turbine sold for ** ____ ** million. All three turbines sold substantially below their original purchase price of ** ____ ** million each [Response to Data Request No. 77 in Case No. EO-2005-0156]. The average price at which Aquila Merchant sold these units in 2003 was ** ____ ** million-- [** ____ ** million plus ** ____ ** million divided by three]. At this average price, it would have been very economical for GMO to have installed any or all of these three Model 7EAs in its service territory to meet its regulated load and increase its generation capacity. These prices compare very favorably with the Crossroads turbine values of ** ____ ** million per unit price for the same Model 7 EAs. Note that these values are for the

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combustion turbines only and do not reflect installation costs, substation costs and other balance of plant costs necessary to operate them.

Aquila Merchant received a total of **____ ** million for the combustion turbines it sold to third parties which had a total capacity of 225 megawatts. This yields a cost of **____ ** per kilowatt. This per kilowatt cost is far below the per kilowatt cost GMO paid for the three Siemens turbines it installed at South Harper in Cass County, Missouri, in 2005. Each of the turbines at South Harper is rated at 105 megawatts, so the capacity of both units is 210 megawatts. Three Model 7EAs is 225 megawatts of capacity. Based on the distressed combustion turbine costs for 2004 to 2005, it would have been more cost-effective for GMO to have installed the 225 megawatts of capacity for the three Model 7EAs at South Harper or another plant site like Aries than to have sold them to third parties for substantial losses that resulted in write-downs in the value of these assets on Aquila's books. The 225 megawatts of capacity for the three Model 7EAs would also resulted in greater overall capacity than adding just two Siemens combustion turbines when comparing those units combined 210 megawatts (Siemens 501D5A rated at 105 megawatts each).

Aquila Merchant originally purchased 18 Model 7 EAs, installing ten at two different site locations in Illinois (Raccoon Creek and Goose Creek) and four Crossroads turbines in Mississippi. Aquila Merchant sold three other turbines s to Colorado and Nebraska entities and the last Model 7 EA was released back to the manufacturer General Electric, with a loss of reservation (option) payments. Like the Siemens turbines installed at South Harper, Aquila Merchant offered several of these Model 7EA turbines for sale, including to KCPL, before executing contracts to sell them. But Aquila Merchant never offered to sell any of these Model 7 EAs to Aquila for use by MPS—at that time L&P did not need capacity, nor did any of Aquila's management, some of who also managed Aquila Merchant, consider using them to serve its retail customers. GMO (Aquila) never considered using these turbines for its regulated operations, even though Aquila needed to replace by June 2005 the capacity and energy it was then getting from Aries under a five-year purchased power agreement. According to GMO these turbines were sold in 2003, in advance of its decision to install turbines at South Harper. (Response to Data Request No. 43, Case No. EO-2005-0156).

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CROSSROADS DEFERRED INCOME TAXES

In GMO's 2010 rate case, in determining what impact Crossroads had on GMO's revenue requirement for MPS, the Commission considered the level of deferred income taxes (deferred taxes) to use as an offset to its rate base valuation of Crossroads. The Commission used $15 million for the deferred income taxes which was included in the revenue requirement for MPS the Commission issued in its May 4, 2011 Order.

The Commission stated the following at 96 of its Order in the 2010 GMO rate case:

> Since Crossroads became part of the non-regulated operations of Aquila Merchant in 2002, deferred income taxes accumulated. In all instances, KCPL and GMO use deferred income taxes relating to regulated investment assets as an offset (reduction) to rate base, except now for Crossroads. It is GMO's position that since Crossroads was not part of its regulated operations when those deferred taxes were created, they should not be used as an offset to MPS's rate base now. If the Commission authorizes GMO to rate base Crossroads in this case, then it is Staff's position that all the accumulated deferred income taxes associated with Crossroads should be offset against rate base attributable to MPS.
>
> The accumulated deferred taxes associated with Crossroads should be applied as an offset to MPS's rate base.

After several parties, including GMO, requested the Commission to clarify its May 4, 2011 Order on several issues, on May 27, 2011 the Commission did so with its Order of Clarification and Modification where, on page 2, it stated the following regarding deferred taxes for Crossroads:

> GMO further requested clarification of the Report and Order regarding the accumulated deferred income tax reserve amount for the Crossroads facility. GMO argues that because the Commission valued Crossroads at $61.8 million, which is less than the valuation put forth by GMO, the amount of accumulated deferred income tax also needs to be recalculated based on that lower valuation.
>
> Ag Processing and SIEUA oppose this clarification. Ag Processing and SIEUA argue that because Aquila Merchant was not profitable, it would have never been able to take the benefits of a depreciation deduction without its affiliation with a profitable regulated business. Secondly, Ag Processing and SIEUA argue that, as found by the Commission, Great Plains Energy (GPE) would have considered this deferred tax balance in its valuation of Crossroads when conducting its due diligence before the purchase. Third, AG Processing and SIEUA argue that the Commission's valuation of Crossroads is already generous and thus, the Commission

> should not further "increase" the value by recalculating the deferred income tax reserve amount.
>
> The Commission agrees with Ag Processing and SIEIA's assessment. The Commission set the value of Crossroads considering all relevant factors presented and found GPE had conducted due diligence in its purchase of Aquila, Inc. Therefore, the Commission need not clarify this point in the Report and Order.

In this case, consistent with the Commission's Order in Case No. ER-2010-0356, which the Commission is presently defending before the Missouri Western District Court of Appeals in Case No. WD75038, Staff has used $14.8 million for Crossroads deferred taxes as of March 31, 2012, in developing its revenue requirement for MPS. While this amount is consistent with the level of deferred taxes ordered by the Commission in the last GMO rate case, Staff is willing to discuss with GMO and the other parties in this case the level of the deferred taxes for Crossroads based on the asset values determined by the Commission for Crossroads because of the interrelationship of deferred taxes and plant asset valuations.

CROSSROADS TRANSMISSION COSTS

Because Crossroads is located in Mississippi, GMO has made firm transmission commitments to transport electricity from it to GMO's load center in western Missouri. 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 is E-74.1 in Staff Accounting Schedule 10.

GMO's annual total of transmission costs for Crossroads by year from 2007 through 2011 are:

2011	** ________ **
2010	** ________ **
2009	** ________ **
2008	** ________ **
2007	** ________ **

[Response to Data Request 154, Case No. ER-2012-0175]

As stated above Crossroads was neither, located, designed or built to provide energy to GMO or its MPS service area. This generating facility was located, designed and built as a merchant plant to take advantage of a point of congestion in transmission in the markets for power during periods of peak demand and when transmission service is constrained, *i.e.*, difficult to obtain. Once Aquila and its affiliates decided in 2002 to exit the non-regulated energy markets, using Crossroads to supply electricity to customers in Missouri and elsewhere became difficult due to transmission constraints and the cost of energy from Crossroads relative to the cost of energy from other generating facilities supplying energy in the market.

If GMO had built a generating station similar to Crossroads in or near GMO's service area in 2004 or 2005 before Aquila's five-year PPA for a maximum of 500 megawatts of capacity and energy from Aries had expired on May 31, 2005, it would have ensured that it would incur no transmission costs to supply its customers with capacity and energy from that station. If Aquila had built and rate-based the Aries generating facility as a regulated power plant, as it contemplated in the early 1990s, today it would have sufficient capacity and a site where it could have installed the four combustion turbines sold to third parties or returned to General Electric at a loss. Aquila effective missed many valuable opportunities during the time from 2003 to 2005, and even 2006 to construct low cost power that it could have used throughout this time period. It is important for the Commission to understand that GMO would not be in the capacity shortfall condition they are in now if Aries had been retained or reacquired, as it attempted to do in late 2006, or had built additional capacity using turbines at substantial discounted values.. Had it built generating capacity in and around its service area, it would not be incurring significant transmission costs to serve its retail customers—certainly not the level of transmission costs it has been incurring to transport energy from Clarksdale, Mississippi, to the Kansas City-Sedalia, Missouri, area.

No prudent Missouri PSC regulated utility would build peaking capacity in Mississippi over 500 miles from its retail customer load centers in western Missouri. Certainly, no regulated utility should choose to build peaking capacity at such a location when it could avoid incurring several millions of dollars in transmission costs each year to transport the energy from that facility to its retail customers. This Commission rightly recognized in GMO's last general electric rate case that GMO's retail customers in Missouri should not bear the high transmission costs of energy from Mississippi and refused to include them when developing GMO's revenue requirement for MPS when it was GMO and its affiliates who made the decisions that led to GMO relying on a generating facility in Mississippi, which is located so far away from its retail customers in Missouri.

Staff Expert/Witness: Cary G. Featherstone

5. Capacity Allocation Between Rate Districts – Ralph Green

Staff has assigned GMO's natural gas 71 megawatt Ralph Green combustion turbine from MPS to L&P based on Staff witness Lena M. Mantle's analysis of GMO's capacity needs and resources for its MPS and L&P rate districts. Staff made adjustments to both its MPS and L&P revenue requirement models to reflect the assignment of the Ralph Green combustion turbine's plant and accumulated depreciation reserve and operation and maintenance costs to L&P.

Additionally, Staff has assigned from L&P to MPS, GMO's ** ____________________ ____ **

Staff Expert/Witness: Cary G. Featherstone

6. St. Joseph Landfill Gas Generating Plant

GMO constructed a landfill gas generating plant at the St. Joseph city landfill. Staff and Company personnel agreed on a set of in-service criteria[66] to determine when Staff and GMO would consider the generating unit to be fully operational and used for service for purposes of recommending to the Commission that the plant be considered for inclusion in rate base. These criteria, which can be found, with Staff's evaluation notes, attached to this report as Appendix 3, Schedule MET-1, have been utilized in other reviews for generating units[67].

The St. Joseph Landfill Gas Generating Plant consists of one (1) reciprocating internal combustion engine and associated generator, rated at a nominal one and six-tenths (1.6) MW. Landfill gas is extracted from wells in the landfill and supplied to the engine. This gas contains approximately fifty percent (50%) methane. The generator connects to the GMO distribution system through an on-site step-up transformer. Staff considers the plant to satisfy relevant Missouri statutes and regulations to qualify as a renewable energy resource and receive the one and twenty-five hundredths (1.25) credit for in-state facilities.

Based on Staff's on-site observation of the facility supplemented by review of test records, operating logs, computer data, and other documentation, Staff concludes that the generating unit has successfully met all of the in-service criteria and was fully operational and used for service by March 30, 2012. This date is later than the end of the test year (September 30, 2011) for this case, but is within the update period ending March 31, 2012 and true-up period ending August 31, 2012.

Staff Expert/Witness: Michael E. Taylor

[66] In-service criteria are a set of operational verifications to implement the requirements of Section 393.135, RSMo.
[67] Criteria were modified relative to those utilized for other generating units due to the unique configuration and operating characteristics of this specific generating unit.

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B. 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 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. Because the 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 September 2010 to March 2012. If an upward or downward trend was detected, then Staff used ending balance for that account. If there was no discernible trend, then a 13-month average was figured and determined to be the most appropriate measure of the ongoing expense for that account. Staff examined the accounts individually and determined which methodology, 13-month average or ending balance, was the most appropriate measure to accurately predict the ongoing future of a particular account (Accounting Schedule 2).

Staff Expert/Witness: Patricia Gaskins

C. Prepayments

Staff's recommended treatment of prepayments is to examine each prepayment account individually in order to determine an appropriate measure that most accurately predicts the ongoing future expense of a particular prepayment account, and then to include the prepayments in GMO's rate base. Prepayments are the costs a company incurs and pays in advance. GMO buys property insurance to protect its assets, the costs of which are treated as a prepayment and included in rate base. 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 examined all of GMO's prepayment account balances dating back to GMO's previous rate case (ER-2010-0356) through March 31, 2012, on a month-by-month basis. Based on this review, and the variability in the monthly account balances, Staff determined the prepayment levels to be included in GMO's rate base. These amounts were determined by multiple methodologies, including: calculating an average based on balances for the 13-months ending March 31, 2012. Staff used this approach on accounts where there was no discernible upward or downward trend in the monthly balances. Staff also used the most recent account balance (March 31, 2012) on accounts where a noticeable upward or downward trend was present.

Staff did not include prepayments related to gross receipts taxes. While GMO includes gross receipts taxes as a prepayment, these costs are actually paid in arrears and as a result, Staff excluded these taxes from prepayments. The cash flow impact on GMO for gross receipts taxes is reflected in Staff's Cash Working Capital calculation as shown on Accounting Schedule 8. The Commission should base its awarded revenue requirement on Staff's recommended appropriate measure of prepayments added to GMO's rate base, indicated in Accounting Schedule 2. Staff further recommends that prepayment expenses should not include prepayments for gross receipts taxes.

Staff Expert/Witness: Patricia Gaskins

D. Cash Working Capital

Cash Working Capital ("CWC") is the amount of cash necessary for a utility to pay the day-to-day expenses incurred 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.

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.

In GMO's prior rate case (ER-2010-0356), Staff performed a partial study analyzing gross receipts taxes (GRT) and injuries and damages (I&D) while relying on calculations made by GMO and the Staff in previous cases for all other lags. GMO has adopted the GRT and I&D lags developed by Staff and is essentially using the same expense lags used by Staff in the 2010 rate case.

The retail revenue lag (the average number of days between when service is provided to customers and when payment for the service is received by the utility) used by GMO in this case is made up of four components: service period lag, billing lag, collection lag and float lag. Staff does not use a float lag in its calculation of the retail revenue lag.

GMO used a service period lag of 15.25 days to reflect the 2012 leap year. Staff is using 15.21 days of service period lag because Staff does not reflect the 2012 leap year in its calculation. Staff removes the effects of the leap year in the case, including any leap year revenues. Therefore, Staff is not including the effects of leap year on revenue lags in this case.

Staff and GMO each used a billing lag of 2 days. For reasons discussed in detail in the GMO Accounts Receivable Bank Fees section of this report, GMO did not have an accounts receivable sales program in effect when it filed its direct case on February 27, 2012. Because GMO anticipated that it would "enter into an accounts receivable sale program prior to the true-up date" (GMO witness John P. Weisensee direct testimony, page 28, lines 11 and 12), GMO calculated a collection lag consistent with the methodology used by KCPL, which currently participates in an accounts receivable sales program. As explained later in this report, GMO entered an agreement to sell its accounts receivable effective May 31, 2012. Staff has updated GMO's collection lag calculation through the period ended March 31, 2012 and will recalculate the collection lag for Staff's true-up filing.

The Cash Working Capital Schedule 8 identifies the amount of cash working capital to be reflected in a company's cost of service. Staff's CWC analysis results are reflected on the Rate Base Accounting Schedule 2 in the section "Add to Net Plant In Service." Staff's CWC analysis results used in the Schedule 2 section titled "Subtract From Net Plant" reflect the amounts of Federal Tax Offset, State Tax Offset, City Tax Offset and Interest Expense Offset.

Staff Expert/Witness: V. William Harris

E. Fuel Inventories

1. <u>Coal Inventory</u>

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 level of native load for GMO. Staff obtained from the fuel model an annual amount of tons of coal burned by each coal-fired generating unit during the normalized test year. Staff divided the annual tons of coal burned from the fuel model by 365 days to calculate the average daily burn. Staff then multiplied this average daily burn by an appropriate number of days of coal inventory for each generating unit and added an estimated level of basemat coal. Basemat is the bottom portion of the coal pile that is not suitable as fuel due to contamination by items like soil and clay. Staff then multiplied the resulting normalized level of inventory for each unit by the delivered cost per ton of coal for use at that unit. The resulting annual coal costs for each unit were then aggregated for the units of MPS and L&P; those aggregated amounts were then multiplied by Staff's energy jurisdictional allocator to arrive at the coal inventory amount shown as coal inventory in Rate Base Schedule 2.

Staff used current delivered prices to determine the rate base inventory value for the estimate of basemat coal inventory. Basemat is not considered readily available for use and an amount of this contaminated coal acts as a buffer between the ground and readily burnable coal. Staff is continuing to evaluate the appropriateness of using a current delivered price for this inventory as opposed to a historical average price.

Staff Expert/Witness: Bret G. Prenger

2. <u>Oil and Fuel Additive Inventories</u>

Staff used 13 month averages to determine the inventory levels for oil and other fuel additive inventories. When inventory levels fluctuate from month to month, as they generally do with fuel stocks, a 13-month average is used to smooth out those fluctuations.

A 13-month average of inventory reflects the Company's actual experience from the entire test year period by including a beginning and ending inventory. For example, if the test year were a calendar year it would begin January 1 and end December 31. A 13-month average would reflect the entire year by using the December 31 (January 1) balance and including each subsequent month-ending balance through December 31. Twelve month-ending balances from January 31 through December 31 do not accurately reflect the Company's actual experiences because they ignore the impact of the period from January 1 through January 30.

Rate Base Schedule 2 reflects Staff's inventory levels for coal, oil and other fuel inventories.

Staff Expert/Witness: Bret G. Prenger

F. Customer Deposits

Staff's recommended treatment of customer deposits is to deduct the most current customer deposit balance from GMO's rate base. Customer deposits are the funds required to be provided by certain customers taking electrical service from GMO. These funds are deducted from GMO's rate base because these funds are cost-free funds received by GMO. The amount reflected for customer deposits on Accounting Schedule 2, Rate Base, is a 13 month average of customer deposit balances as of March 31, 2012 a 13-month average was used because the account balances varied month to month. 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, and that interest expense is included as an expense in the revenue requirement calculation (discussed in more detail in a separate 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 rate base.

Staff Expert/Witness: Patricia Gaskins

G. Customer Advances

Staff's recommended treatment of customer advances for the MPS rate district is to deduct a 13-month average of account balances ending March 31, 2012, from MPS' rate base. Staff further recommends that for customer advances within the L&P rate district, the most current customer advances balance be deducted from L&P's rate base. Staff used two different accounting methods for GMO's two rate districts when determining the appropriate level of customer advances to offset GMO's rate base because the monthly account balances for MPS did not exhibit a discernible upward or downward trend, so a 13-month average was determined to be the most appropriate level of customer advances as an ongoing level of expense. Staff identified a steady or ongoing trend in L&P's customer advances accounts; and, therefore, Staff recommended the most current customer advance ending balance be used. Customer advances are funds typically provided by 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. Customer advances are included in the rate base as an offset, reducing the amount of overall investment that customers must supply as a return to the utility (Accounting Schedule 2).

The amount of customer advances reflected on Accounting Schedule 2, Rate Base, represents a 13-month average of balances from the Update Period for MPS, and represents the most current balance of the account (ending March 31, 2012) for L&P. The Commission should base its awarded revenue requirement on Staff's recommended deductions for customer advances, where Staff has calculated the appropriate levels of customer advances to deduct from GMO's rate base for the two rate districts, MPS and L&P.

Staff Expert/Witness: Patricia Gaskins

H. Accounting Authority Orders

Staff recommends the Commission include the amortized expense related to two existing accounting authority orders (AAO) to the MPS rate district's cost of service as well as including the unamortized balance of those AAO's to MPS's rate base. Staff also recommends the Commission include the amortized expense related to an existing AAO 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 known as an AAO. Generally, AAOs enable a utility to delay booking an expense in the period it was incurred, and instead book that expense, or an amortized portion of it, in a period used to calculate its cost of service in a future rate proceeding. Depending on the AAO, the unamortized balance may or may not be included in rate base.

MPS currently books an amortized level of expense from two AAO's, issued in Case No. ER-93-37. The unamortized balances for these AAO's are included in MPS's rate base. In 1993 two AAOs were granted by the Commission for the Sibley rebuild project in Case No. ER-93-37.[68] The Commission ordered a 20 year recovery for each of these AAOs. The deferral began in July 1993 and will end in June 2013 for one AAO and for the other; the deferral began in June 1993 and will end in May 2013. Staff included the unamortized balance in rate base for each of these AAOs. In addition, Staff included the annual amortization of these AAO's in Staff's Accounting Schedule 9, Adjustment E-167.1 and E-172.1. Since the amortization period for both AAO's end in 2013, after the effective date of rates in this case, Staff recommends MPS track any over amortization and include the over amortization as an offset for future rate cases.

In 2007, the city of St Joseph, Missouri was struck by a significant ice storm. St Joseph, Missouri is within the L&P rate district. The Company filed an application with the Commission for an AAO to defer the excessive maintenance and operational costs in Case No. EU-2008-0233. The Commission granted the AAO and ordered that the amortization of the costs associated with the storm begins on January 1, 2008 and end on January 1, 2013. This AAO does not receive rate base treatment. Since the amortization period for this AAO will end before the effective date of rates in this case, Staff made an adjustment for the amortization costs through the August 31, 2012 True Up period and is reflected in Staff's Accounting Schedule 9, Adjustment E-191.1. Similar to the AAO's discussed above, Staff recommends L&P track any over amortization and include the over amortization as an offset for future rate cases.

Staff Expert/Witness: Karen Lyons

I. Iatan Construction Accounting Regulatory Assets

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

[68] In Case No. ER-90-101, regarding the Sibley rebuild project, the Commission ordered a 20 year recovery of the costs with the unamortized balance included in rate base. This AAO deferral began in October 1990 and ended in September 2010. Since this AAO has ended, no adjustment was necessary.

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-2009-0089 Stipulation
GMO – MPS and SJLP	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. The Commission authorized GMO to record in that account the depreciation and carrying costs 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 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.

Staff adjusted these regulatory assets pursuant to the Commission's Report and Order in the most recent prior rate case, Case No. ER-2010-0356.

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 in MPS Adjustment E-173.1 and L&P Adjustment E-192.1.

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 referenced 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 in MPS Adjustment E-173.2 and L&P Adjustment E-192.2.

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 in MPS Adjustment E-173.3 and L&P Adjustment E-193.1.

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 referenced 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 in MPS Adjustment E-173.4 and L&P Adjustment E-193.2.

Staff Expert/Witness: Keith Majors

VIII. Income Statement – Revenues

A. Rate Revenues

1. Introduction

This section describes how Staff determined the level of GMO Operating Revenues for both the MPS rate district and the L&P rate district. Since the largest component of operating revenues result from rates charged to GMO's retail customers, a comparison of operating revenues with cost of service is fundamentally a test of the adequacy of the currently effective Missouri retail electricity rates. If the overall cost of providing service to Missouri retail customers exceeds operating revenues, an increase in the current rates GMO charges its Missouri retail customers for electricity may be appropriate. Because GMO has two rate districts, Staff determined operating revenues and cost of service for each rate district, MPS and L&P.

One of the major tasks in a rate case is to determine the magnitude of any deficiency (or excess) between cost of service and operating revenues. Once determined, the deficiency (or excess) can only be made up (or otherwise addressed) by adjusting Missouri retail rates (i.e., rate revenue) prospectively. Operating Revenues are composed of Margin from Off-system Sales, Other Operating Revenue and Rate Revenue.

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

Staff Expert/Witness: Curt Wells

2. The Development of Rate Revenue

To determine the level of MPS and L&P district rate revenues, Staff applied standard ratemaking adjustments to test year (historical) usage (kWh) and revenue data for both MPS and L&P service areas. The intent of Staff's adjustments to the test year Missouri rate revenues is to determine the level of revenue that the Company would have collected from the customers in each district on an annual basis, under normal-weather or climatic conditions, based on information "known and measurable" by the end of the Update Period of April 1, 2011 through March 31, 2012. Rate revenue for both rate districts has been developed and summarized in two different ways: one way is by type of regulatory adjustment; and a second way is total rate revenue by rate class. The Rate Revenue Summary Tab of the Staff Accounting Schedules summarizes rate revenue both ways, i.e., by type of adjustment and by rate class. The rate classes shown for the MPS rate district are Residential (RES), Small General Service (SGS), Large General Service (LGS), Large Power Service (LPS), Special, and Lighting. For the L&P rate district classes shown are Residential (RES), General Service (GS), Large General Service (LGS), Large Power Service (LPS), and Lighting. Staff workpapers provide the source numbers and analysis for the individual rate codes, and present a much more detailed version of the summary table.

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

a. weather normalization
b. annualization for the rate change
c. 365-day adjustment
d. customer growth
e. large customer Annualization and rate switching by large customers
f. customer discounts

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

Staff Expert/Witness: Curt Wells

3. Regulatory Adjustments to Billing Unit and Rate Revenue

a. Treatment of Unrecovered Phase-In Revenue

As a result of previous rate cases (ER-2010-0356 and ER-2012-0024), revenue in the amount of $7,671,708 was deferred from June 25, 2011, until June 25, 2012, when recovery began. Recovery was anticipated over a two-year period (June 2012-June 2014) at which time rates would return to the level anticipated to recover the revenue originally required absent the phase-in. The phase-in did not anticipate an intervening rate case.

The timing of this rate case has resulted in an operation of law date of January 26, 2013. By that date, Staff estimates that the L&P rate district will have recovered approximately $2.4 million of the approximately $7.7 million deferred, leaving approximately $5.6 million (including carrying costs) unrecovered.

Staff recommends that the phase-in be cancelled, that the unrecovered $5.6 million be amortized over a three-year period, and that GMO establish a tracker that will be trued-up at the end of the three-year amortization period. The amortization is reflected in Staff's Accounting Schedule 9, Adjustment Rev-2.11. While Staff asserts that this is the most appropriate course of action, due to the uniqueness of this issue, Staff is open to discussing alternatives to this approach with the parties.

Staff Experts/Witnesses: Curt Wells and Karen Lyons

b. Weather Normalization

i. Weather Normal Variables

Historical Data Used to Calculate Normal Weather Variables - Each year's weather is unique; and, consequently, the usage, the hourly loads, the revenue, and the fuel and purchased power expense need to be adjusted to a level that would be expected under "normal" weather conditions. Staff used weather observations for the Update Period of April 1, 2011, through March 31, 2012, from the Kansas City International Airport ("MCI") in Kansas City, Missouri.

As a measure of "normal" weather, Staff used "climate normals" ("normals") published in July 2011 by the National Climatic Data Center ("NCDC") of the U.S. National Oceanic and Atmospheric Administration ("NOAA") as the authoritative definition of normal weather. According to NOAA, a climate normal is defined, by convention, as the arithmetic mean of a climatological element computed over three consecutive decades.[69] To conform to NOAA's three consecutive decade convention 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, the same period in which NOAA bases its calculation of climate normal.

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 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. NCDC confirmed that 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. In addition, NCDC provided a peer-reviewed, published paper[70] to explain the meteorological and statistical soundness of the NCDC's monthly temperature series homogenization procedure for removing documented and undocumented anomalies.

Because Staff used daily temperature observations to calculate normal weather values and NOAA's normals are monthly values, Staff adjusted the observed daily minimum temperatures so that the monthly average minimum temperature calculated from these adjusted daily values is the same as the NCDC's serially-complete monthly minimum 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.

Weather Variables - Because weather fluctuates greatly from day-to-day, the MCI temperature variables required to weather-normalize sales are the Update Period actual temperatures and the 30-year normal two-day weighted daily mean temperatures. The day's

69 Retrieved on July 17, 2012, from NOAA website, http://www.ncdc.noaa.gov/oa/climate/normals/usnormals.html.

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

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.[71]

This weighted mean is used because yesterday's weather effects how electricity is used today. For example, if yesterday was hot and the air conditioner was on, it is more likely that the air conditioner will be left on today. If yesterday was a mild day and today is slightly hotter, air conditioning may not be used or would be turned on later in the day.

Calculation of "Normal Weather" - Staff used the MCI daily two-day weighted mean temperature data series to normalize both class usage and hourly net system loads. Staff used a ranking method to calculate normal weather estimates daily normal temperature values, ranging from the temperature that is "normally" the hottest to the temperature that is "normally" the coldest, thus estimating "normal extremes." 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 method results in the normal extreme being the average of the most extreme temperatures in each year of the 30-year period. The second most extreme temperature is based on the average of the second most extreme day of each year, and so forth.

Because actual temperatures do not smoothly move up and down from day to day during the year,[72] Staff assigned these normal temperatures to the days of the Update Period based on the rankings of the actual temperatures of the Update Period.

This information was used by Staff witness Shawn E. Lange to normalize both the class kWh usage and hourly net system loads.

Staff Expert/Witness: Seoung Joun Won

ii. Weather Normalization of kWh

Staff's recommended treatment of Weather Normalization is to: 1.) normalize the most current 12-month period available when calculating normalization adjustments, and 2.) utilize

71 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: $TWMT_D = (2/3)\ DMT_D + (1/3)\ DMT_{D-1.}$

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

daily load research data to determine non-linear class 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 for the normalization of revenues for the RES, SGS, and LGS classes.

In many of the classes of service, electricity consumption is highly responsive to the weather, specifically temperature. As the temperature reaches higher levels, the demand for cooling, air conditioning, and fans increases the customers' consumption of electricity. As the weather becomes colder and temperature falls, the demand for additional heating, for example electric space heating, also forces an increase in customers' consumption of electricity. Electric air conditioning and space heating are prevalent in GMO's service territory; and, therefore, it follows that GMO's electric load is linked and responsive to temperature. The reaction to temperature in the MPS rate district differs from the reaction to temperature in the L&P rate district. Therefore, each rate district was analyzed separately.

In an attempt to capture a more current, forward-looking indictor of non-weather electricity usage per customer, Staff reviewed and analyzed the most recent temperature and load data available. Staff based its analysis on the Update Period of April 1, 2011, through March 31, 2012, analyzing load research data for the 12-month period ending December 31, 2011.

December 2011 and January 2012 were warmer than normal, resulting in electric energy usage below that which would have been expected under normal weather conditions. May 2011 through August 2011 were also warmer than normal, resulting in usage above that which would have been anticipated under normal conditions. Since the temperatures in the Update Period used by Staff deviated from normal weather conditions and since Staff chose a more recent test year to review than the one used by GMO, Staff performed its own weather impact analysis. However, the method and models used by Staff are similar to those used by GMO.

Staff's model and methodology contained elements important in the weather-normalization process used at the retail class level: use of daily load research data to determine non-linear class 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 witness Curt Wells to be used in the normalization of revenues for the RES, SGS, and LGS classes.

Staff did not normalize weather for the Large Power Services (LPS) class, but instead annualized the LPS class for changes in customer usage and count. The members of this class are not homogeneous; and, consequently, a weather response function created for one member should not be applied to any other member. Staff concluded it is both appropriate and necessary to annualize rather than normalize the LPS class for changes in customer usage and count. Applying the weather normalization process to annualized usage would have introduced statistical error into the product of the analysis. Please see *Large Power Annualization* by Staff witnesses Robin Kliethermes and Kim Cox for a more detailed explanation of the annualization adjustments for the LPS classes.

The Commission should base its awarded rate revenue on Staff's recommended Weather-Normalization analysis.

Staff Expert/Witness: Shawn E. Lange

iii. The Effect of the Weather Normalization on Rate Revenue

Based on the analysis performed by Staff Witness Shawn Lange, Staff adjusted the Company's weather normalization adjustments for kWh usage. Weather normalization only affects the energy usage of each existing customer and thus only affects those charges directly related to kWh usage. Weather normalized rate revenue results from applying billing rates to billing units including this adjusted kWh usage.

Staff Expert/Witness: Curt Wells

c. Annualization for Rate Change

One important determinant of rate revenues in this case is the annualization of rates. A portion of the rate revenues included in the Update Period reflect rates prior to current rates. Thus, the Update Period revenues for the MPS and L&P rate districts are understated by the difference between the amount that was actually billed to customers prior to current rates and the revenue that would have been realized by GMO if the current rates had been in effect throughout the entire period. Staff computed annualized revenues for each class by applying the appropriate rates to test year annualized billing units for each class. These adjustments affected all rate classes in both rate districts.

The MPS rate district was annualized to its current rates (effective June 25, 2011). Although the L&P rate district rates increased on June 25, 2012, Staff based the rate change annualization for this rate district on the proposed June 25, 2014 rates which better reflect the required revenue determined by these cases absent the phase-in. The phase-in is now in the first year of a two-year phase-in adjustment created to enable GMO to recover the deferred portion of the increase ordered in Case Nos. ER-2010-0356 and ER-2012-0024. Staff's recommendation on the disposition of Phase-in revenues is covered in more detail below.

Staff Expert/Witness for MPS Large Power: Robin Kliethermes

Staff Expert/Witness for L&P Large Power: Kim Cox

Staff Expert/Witness for all other classes: Curt Wells

d. 365-Days Adjustment

i. 365-Days Adjustment to Usage of Weather Sensitive Classes

Staff's recommended treatment of the *365-Days Adjustment* is to adjust the revenues of the weather-normalized class revenue months to the twelve month calendar period ending March 30, 2012. Since the Update Period includes February 29, 2012, it was necessary to remove a day from the Update Period in order to obtain 365 days of usage; this day was March 31, 2012.

Staff calculated a normalization adjustment to GMO's kWh usage to reflect a calendar year's (365 days) worth of usage. GMO's customers' usage is measured and rate revenues are collected over a period known as a revenue month, which represents the interval GMO reads customers' meters and issues bills. A bill rendered for a given revenue month may charge for usage in parts of two calendar months. Revenue months take their names from the calendar month in which the customer's bill is rendered. For example, assume a customer's meter was read and usage determined on June 8 and then again on July 8 and that the bill was sent to the customer on July 15. The revenue month for this bill is July even though 22 days of the usage measured for this bill occurred from June 9 through June 30 and it contained only eight days of usage in July.

The length of a revenue month is dependent upon the interval between meter readings and does not necessarily have the same number of days that occur in a given calendar month of the same name; that is, a revenue month may have more than, or less than, the number of days for the same-named calendar month. For the example given above, the usage is for 30 days (June 9 through July 8) even though the revenue month is July which has 31 days. When the revenue month usage is totaled over the year, the resulting revenue year will include usage from the immediately prior calendar year and assign usage to the next calendar year, meaning a revenue year may contain more than or less than 365 days' usage. Therefore, since the costs and expenses are accounted for over a calendar year, Staff calculates an annualization adjustment to bring the revenue year kWh into a 365-days interval. This adjustment is stated in kWh and is referred to as 365-*Days Adjustment.*[73]

Staff calculates the *365-Days Adjustment* by subtracting the weather-normalized revenue month kWh from the weather-normalized calendar month kWh for the test year; the difference, or the *365-Days Adjustment*, may be either positive or negative. The resulting normalized adjustment calculates an annualized *365-Days Adjustment*, which was applied by Staff witness Curt Wells to the weather sensitive classes in order to adjust the revenues of the weather-normalized class revenues months to the twelve month calendar period ending March 30, 2012. The Commission should base its awarded revenue requirement by applying the *365-Days Adjustment* when accounting for the weather sensitive classes of customers' usage.

Staff Expert/Witness: Shawn E. Lange

ii. 365-Days Revenue Adjustment for Weather Sensitive Classes

Staff calculated its revenue adjustment for weather sensitive classes by allocating the "365-days" kWh adjustment proportionately to the appropriate revenue month weather normalized kWh usage for each class and then applied current rates. The difference between the revenues calculated in this way for each class, and the test year revenues for the class, determined the amount of the *365-days adjustment*.

Staff Expert/Witness: Curt Wells

iii. 365-Days Adjustment for Large Power

The bill cycles representative of the 12 months ending March 2012, ("Update Period") for each customer may or may not include 365 days. For the Large Power Service ("LPS") class in both MPS and L&P rate districts, Staff makes a monthly adjustment to those customers whose monthly usage for the Update Period does not include 365 days by either adding the appropriate number of days of average kWh usage when there were less than 365 days of usage, or subtracting the appropriate number of days of usage when there were more than 365 days of

[73] Days adjustments are also known as adjustments to unbilled usage and unbilled revenues on financial statements.

usage. Specifically, the MPS rate district had a bill cycle change that resulted in either a short April revenue month of less than 26 days in the billing period or a large May revenue month of more than 35 days in the billing period for specific customers. These billing periods caused the Update Period usage to contain less than, or more than, 365 days. Therefore, revenue months containing less than 26 days or more than 35 days were normalized to 30 days, by either adding additional kWh usage to that specific month or subtracting the appropriate kWh usage from that specific month. The L&P rate district had two occasions where an adjustment was made because the revenue month covered less than 26 days. After the normalization was calculated, the 365-days adjustment for the Update Period 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 "days" revenue adjustments.

Staff Experts/Witnesses: Robin Kliethermes for MPS and Kim Cox for L&P

B. Customer Growth

Staff made customer growth adjustments to test year kWh sales and rate revenue to reflect the additional kWh sales and rate revenue, which would have occurred if the number of customers taking service at the end of the update period (March 31, 2012) had existed throughout the entire test year. For MPS, customer growth was calculated for the MO815, MO860, MO865, MO866, and MO870 Residential rate classes, MO710, MO711 and MO868 Small General Service rate classes and the MO720 Large General Service rate class. For L&P, customer growth was calculated for the MO910 and MO920 Residential rate classes, and the MO940 Large General Service rate class. Staff calculated customer growth for the Residential, Small General Service, Medium General Service, and Large General Service rate classes using customer levels as of March 31, 2012.

Staff Expert/Witness: Karen Lyons

C. Additional Revenues from Customer Growth During the Update Period

For this Direct Testimony filing, Staff updated all elements of revenue, expense, and rate base over the 12 month period ended September 30, 2011, test year level and for any known and measurable changes through March 31, 2012. A review of the pertinent facts as of March 31, 2012, indicates that MPS experienced an increase in its overall growth in the number of its utility customers and L&P experienced a decrease in its overall growth in the number of its utility customers. For Residential and General Service (Small, Medium, and Large) retail customer groups, Staff employed the following method of computing the annualized level of decreased revenue from customer growth at March 31, 2012: For each customer rate group, the customer level during each month of the test year is compared to the level as of March 31, 2012, and the monthly change in level is computed. This growth in customers is then multiplied by the weather-normalized revenue per customer experienced for that month of the test year. In this case, weather-normalized revenue was based on the twelve (12) month period from April 1, 2011, through March 31, 2012.

Staff's approach assumes that the revenue pattern experienced in each month of the test year will recur on a weather-normalized basis, factored up (or down) in accordance with the growth (or decrease) in customer numbers at March 31, 2012.

The only retail customer rate group for which this approach is not taken is the Large Power group. With respect to Large Power customers, energy consumption and revenue patterns vary significantly across this group of customers, making it necessary to examine the history of each customer on an individual basis, and to adjust the test year revenue level for each customer accordingly. A detail of Staff's position related to Large Power customers is located under the heading *Large Customer Rate Switching and Annualization* in this report. Staff's customer growth adjustment to test year revenues for all retail customer groups combines the results of the analysis described above for Residential, General Service, and Large Power customers in order to provide the annualized level as of March 31, 2012. The retail customer growth adjustment other than Large Power is reflected in the Staff Accounting Schedule 9 as Adjustment Rev-2-9 for MPS and Adjustment Rev-2.10 for L&P.

Staff Expert/Witness: Karen Lyons

D. Customer Growth in Usage

Staff adjusted test year kWh sales for customer growth by allocating the additional rate revenue provided by Staff witness Karen Lyons to each billing determinant of each rate code experiencing growth.

Staff Expert/Witness: Curt Wells

E. Large Customer Rate Switching and Annualization

The general intent of an annualization is to re-state the test year kWh as if conditions known at the end of the Update Period had existed throughout the entire year. It is customary for Staff to annualize each customer in the LPS rate class on an individual basis due to the entrance of new customers, the exit of existing customers and load growth or decline of specific existing customers.

During the Update Period, fourteen customers in MPS and three customers in L&P were in their respective LPS rate class for less than the full year. These customers were new service customers or switched from one rate class to another ("rate switchers"). Of the fourteen customers of MPS, seven entered and seven left the MPS LPS class; for L&P, all three customers entered the LPS class.

Of the ten customers that entered the LPS class during the Update Period, five were new customers and five were rate switchers from the LGS class. Therefore, the five customers that switched rates from LGS to LPS were annualized by applying LPS rates to the LGS usage for the months they were in LGS. The five new customers to the LPS class were annualized by applying usage that was representative of their existing usage, since they were in the LPS class for less than the Update Period.

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, four LPS customer's loads were adjusted. The load that seemed inconsistent or expected a change in the future was replaced by average numbers from adjacent months or by monthly data from other years when the load seemed a better representation of future consumption. Also, due to an incident at one LPS customer's premise, a significant portion of its load was transferred to one of its LGS accounts for part of the update period. This load was annualized out of the LGS class and into the LPS class.

Staff Experts/Witnesses: Robin Kliethermes for MPS and Kim Cox for L&P

1. <u>Customer Discounts</u>

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 MPS and L&P customers. EDR credits are provided to the customer over a five-year period. The value of the credits is a percentage of the customer's electric bill calculated on the appropriate general application rate schedule. Depending upon which contract year the customer is in, the discount can be as high as 30% (year 1) to as low as 10% (year 5). For the LPS class, Staff annualized the credits by first removing the credits from the customers receiving them, next applying the rate change annualization, and then applying the next year's credit percentage (a decrease of 5% from the previous year's percentage) to the annualized revenue. These discounts are included in the determination of both MPS and L&P revenues because fostering economic development is assumed to be a benefit to all ratepayers.

MPower Rider: The purpose of the MPower Rider is to reduce customer load during peak periods. Customers participating in the MPower Rider receive a payment or credit to curtail at least 25 kW during a fixed number of curtailment events in the curtailment season of June 1st through September 30th. Since these discounts help to defer generation capacity and improve supply, they benefit all ratepayers and are included in the determination of GMO's revenues.

Staff Experts/Witnesses: Robin Kliethermes for MPS and Kim Cox for L&P

F. Off-System Sales

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

Staff Expert/Witness: V. William Harris

1. <u>Net Margin on Non-Firm OSS</u>

Prior to the acquisition of MPS and L&P by Great Plains Energy in July 2008 GMO, formerly Aquila, experienced significant and profitable levels of OSS and OSS margins, as illustrated by the table below. However, since the 2008 acquisition, GMO's off-system sales levels and OSS margins have significantly decreased. In 34 of the past 36 months, GMO has incurred greater off-system sales costs than revenues.

MPS OSS levels and net margins since 2002 are as follows:

12-month period ended	MPS Total Account 447030 Off-System Sales	MPS Account 447030 Net Margin	MPS Net Margin %
12/31/2002	** ______ **	** ______ **	9.36%
12/31/2003	** ______ **	** ______ **	20.25%
12/31/2004	** ______ **	** ______ **	28.99%
12/31/2005	** ______ **	** ______ **	46.98%
12/31/2006	** ______ **	** ______ **	16.60%
12/31/2007	** ______ **	** ______ **	14.16%
12/31/2008 GPE acquired Aquila	** ______ **	** ______ **	21.93%
12/31/2009	** ______ **	** ______ **	(29.71%)
12/31/2010	** ______ **	** ______ **	(36.24%)
12/31/2011	** ______ **	** ______ **	(19.27%)
12 months ended 03/31/2012	** ______ **	** ______ **	(23.62%)

L&P OSS levels and net margins since 2002 are as follows:

12-month period ended	L&P Total Account 447030 Off-System Sales	L&P Account 447030 Net Margin	MPS Net Margin %
12/31/2002	** ______ **	** ______ **	30.85%
12/31/2003	** ______ **	** ______ **	61.89%
12/31/2004	** ______ **	** ______ **	66.32%
12/31/2005	** ______ **	** ______ **	42.15%
12/31/2006	** ______ **	** ______ **	61.97%
12/31/2007	** ______ **	** ______ **	62.12%
12/31/2008 GPE acquired Aquila July 14, 2008	** ______ **	** ______ **	61.21%
12/31/2009	** ______ **	** ______ **	(80.26%)

12/31/2010	** **	** **	(43.57%)
12/31/2011	** **	** **	(81.69%)
12 months ended 03/31/2012	** **	** **	(100.11%)

While GMO's off-system sales have shown significant declines since the acquisition, GMO's reliance on purchased power from KCPL has increased substantially since 2008. The following table shows the levels of purchased power sold from KCPL to GMO:

12-month period ended	KCPL Sales to Aquila/GMO	Aquila/GMO Sales to KCPL	KCPL/(Aquila) Net Sales
12/31/2005	** **	** **	** **
12/31/2006	** **	** **	** **
12/31/2007	** **	** **	** **
12/31/2008 GPE acquired Aquila July 14, 2008	** **	** **	** **
12/31/2009	** **	** **	** **
12/31/2010	** **	** **	** **
12/31/2011	** **	** **	** **
6 months ended 06/30/2012	** **	** **	** **

Staff notes that sales from Aquila to KCPL were greater than sales from KCPL to Aquila before the merger whereas 2011 sales from KCPL to GMO exceeded sales from GMO to KCPL by over ** ________ **. Staff will continue to examine the relationship between GMO's declining off-system sales levels and GMO's significant increases in purchases from KCPL.

Since there have been significant downward trends in OSS levels and net margins for both MPS and L&P since the merger and Staff cannot explain or accept negative sales margins, Staff is including in its direct filing the margins for MPS and L&P that GMO included in its updated case as of March 31, 2012. Staff will continue to monitor GMO's off-system data as it

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becomes available during the true-up period ending August 31, 2012. At the end of the true-up period, Staff may propose other appropriate adjustments as necessary.

Staff Expert/Witness: V. William Harris

2. <u>Removal of Inter-Company/Rate District Energy Transfers</u>

This adjustment eliminates inter-company energy transfers between the MPS and L&P rate districts that were recorded during the test year. The source for the revenues and expenses associated with the eliminated energy transfers for both MPS and L&P rate districts is the actual per book amounts for the test year ended September 30, 2011.

Staff Expert/Witness: V. William Harris

G. Transmission Revenue

GMO annually files a transmission formula rate with the FERC to determine the revenue requirement and rate level for transmission service provided through the Southwest Power Pool Open Access Transmission Tariff. The ROE allowed by the FERC in the formula rate is 11.1 percent. GMO is requesting an ROE of 10.4 percent in this case. This adjustment reflects the difference in the transmission formula rate that results from using each respective ROE. Staff will adjust this amount to reflect the final ROE determined by the Commission in this case.

Staff Expert/Witness: V. William Harris

H. SO2 Emissions Allowances

1. <u>Deferred Sales from SO2 Emissions Allowances</u>

GMO receives SO2 emission allowances ("SO2 allowances") from the U.S. Environmental Protection Agency ("EPA"). GMO uses these allowances to serve its native load customers. In addition to these allowances, the EPA also holds back a certain number of 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 ("FERC USOA"), proceeds from the sales of SO2 emissions allowances are recorded in FERC Account 254, the FERC USOA 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.

Staff has included in its direct case the balance of Account 254 on March 31, 2012, as an offset to rate base. This approach is consistent with the treatment in the last three GMO/Aquila rate cases, Case Nos. ER-2007-0004, ER-2009-0090 and ER-2010-0356. The rationale for treating these SO2 emissions allowances in this manner is to acknowledge that, through rates, GMO's customers have paid for GMO's production facilities that create these SO2 emissions allowances.

Staff Expert/Witness: V. William Harris

I. Miscellaneous Revenues

1. Late Payment Revenue (Forfeited Discount)

MPS and L&P charge 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 both net of gross receipt taxes (GRT) from April 1, 2011, through March 31, 2012. This ratio was multiplied by the Staff annualized revenue resulting in an annualized level of late payment fees. This is reflected in the Staff Accounting Schedule 9 as Adjustment Rev-15.1 for MPS and Rev-11.1 for L&P.

Staff Expert/Witness: Karen Lyons

J. Other Revenue Accounts

Staff reviewed the amounts MPS and L&P included in its cost of service calculation for "Other Revenues," which include, but not limited to, forfeited discounts[74] rent from electric property, miscellaneous service revenues, replacement of damaged meters, disconnect service charge, and temporary installation profit. Staff has also included revenue related to transmission at the test year level. The analysis of these amounts included a review of the revenues over the last ten years through March 31, 2012. In Staff's opinion, the test year amounts for Other Revenues appear to be representative and reasonable of an annualized level of revenue for each

[74] Forfeited discounts are also referred to as late payment fees.

respective category and, therefore, do not require adjustment. Staff will examine these revenue accounts again during its true-up audit, which will go through August 31, 2012.

Staff Expert/Witness: Karen Lyons

K. Regulatory Adjustments Result

Rate revenue, for both the MPS and L&P rate districts, with adjustments, are at the Rate Revenue Summary Tab of the Staff Accounting Schedules.

Staff Expert/Witness: Curt Wells

IX. Income Statement – Expenses

A. Fuel and Purchased Power Expense

Staff estimates the variable fuel and purchased power expense for GMO for the twelve months ending March 30, 2012, to be $184,809,060.

In determining the variable and fuel purchased power expense, Staff used the RealTime™ production cost model to perform an hour-by-hour chronological simulation of GMO's generation and power purchases. Staff used this model to determine the annual variable cost of fuel, which includes the net purchased power energy costs and the fuel consumption necessary to economically meet GMO's hourly load requirements during the test year (as updated), within the operating constraints of GMO's resources. These amounts are supplied to the Auditing Department Staff who used this input in the annualization of fuel expense.

The model operates in a chronological fashion, meeting each hour's energy demand before moving to the next hour. It will schedule generating units to dispatch in a least cost manner based upon fuel cost and purchased power cost while taking into account generation unit operation constraints 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.

Inputs calculated by the Staff are fuel prices, firm purchased power contract specifications, spot market purchased power prices and availability, hourly Net System Input ("NSI"), and unit planned and forced outages. The Staff relied on GMO responses to data requests, and data GMO supplied to comply with Rule 4 CSR 240-3.190, for factors relating to each generating unit such as capacity of the unit, unit heat rate curve, primary and startup fuels, ramp-up rate, startup costs, fixed operating and maintenance expense. Information from 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: David W. Elliott

1. Fixed Costs

Fuel and purchased power costs that do not vary directly with fuel burned were determined independent of Staff's fuel model. The non-variable fuel costs that were determined separately and included in fuel expense are typically referred to as fuel adders. The non-variable purchased power costs not included in the Staff's fuel model are commonly referred to as capacity (or demand) charges and are annualized separately from purchased power energy costs. Adjustments of these costs for MPS and L&P are in Accounting Schedule 10.

Staff Expert/Witness: Bret G. Prenger

2. Fuel Adders

Fuel adders do not vary directly with the amount of electricity produced, so these costs are not included in Staff's fuel model. The costs of fuel adders are determined separately and are then added to the level of fuel expense calculated by the model to determine overall fuel expense. Costs that are added to coal expense include unit train lease payments and unit train maintenance costs. Other fuel adders include non-labor fuel handling, gas pipeline reservation charges, ammonia, urea, limestone and powder activated carbon (PAC).

For natural gas fixed transportation costs, Staff used the actual expenses for the 12-months ending March 31, 2012. For additives such as limestone and ammonia, Staff used the calendar year 2011 actual expenses. Staff will update these expenses at the time of Staff's true-up.

Staff Expert/Witness: Bret G. Prenger

3. Hedge Settlements

In GMO's most recent Fuel Adjustment Clause ("FAC") prudence review, Case No. EO-2011-0390, which is currently pending before the Commission for decision, Staff is recommending that the hedging losses associated with GMO's hedging for purchased power costs not be charged to its regulated customers, but retained by GMO's shareholder. Staff's position is that the hedging program is imprudent and has resulted in needless additional costs to GMO's retail customers. Additionally, GMO has accounted for a significant portion of its hedging costs improperly by booking them to Account 547, Fuel, instead of Account 555, Purchased Power.

Staff's adjustment in this rate case is consistent with its position in Case No. EO-2011-0390. First, Staff determined that portion of hedging losses charged to Account 547, Fuel, in the test year. Next, Staff removed the portion of this amount which was related to hedging for purchased power and added that amount to the test year per book Account 555, Purchased Power. Finally, Staff made an adjustment to remove from the adjusted purchased power account balance all hedging gains and losses. To make this final adjustment, the Staff compared the budgeted ratio of natural gas MMBtus for fuel burn to the total MMBtus for fuel burn and purchased power hedges. The source of the Staff's calculation is GMO witness Ed Blunk's Schedule WEB-5 in Case No. EO-2011-0390. Staff is engaged in additional discovery in an effort to ensure that the ratio used in Staff's final adjustment is still appropriate and current. If necessary, Staff will modify the ratio it used to make this adjustment and provide it to the Commission.

Staff Expert/Witness: Charles R. Hyneman

4. **<u>Purchased Power – Energy Charges</u>**

The Staff 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 David W. Elliott is responsible for determining the appropriate amount of power to be purchased, and the proper price to pay for that power. L&P Fuel Adjustments: E-6.2, 43.1, 44.1, 59.1 and 61.1 MPS Fuel Adjustments: E-5.1, 35.1, 36.1, 36.2, 52.1, 53.1, 54.3, and 55.1.

Staff Expert/Witness: Bret G. Prenger

5. **Purchased Power – Capacity Charges**

Capacity charges, also known as "demand charges," represent fixed amounts that GMO has paid to the entity that reserves megawatt electricity capacity for GMO. GMO contracts the rights for this power with various entities and pays a fixed component for the reserve capacity and the energy component for energy consumed. Generally there is also an amount for operational and maintenance costs that are charged for the usage of energy. The fixed component of these costs is paid by GMO as a demand charge, usually monthly, regardless of the level of power actually purchased. The amount paid is for the "right" to purchase the power, in much the same way natural gas utilities purchase reservation of capacity from pipelines through reservation payments. The demand charges relate to the fixed expenses of operating a generating facility.

Staff annualizes purchased power demand charges for MPS and L&P, based upon the most current capacity contracts. These charges represent amounts that are paid under capacity agreements related to the fixed costs of reserving capacity. Staff has reviewed each of the capacity contracts and has determined the appropriate costs per megawatt hour and the amount of megawatts purchased. Staff included the costs reflected in GMO's capacity agreements that were in effect on March 31, 2012, with plans to update these costs during the true-up period. . L&P Fuel Adjustments: E-6.2, 43.1, 44.1, 59.1 and 61.1 MPS Fuel Adjustments: E-5.1, 35.1, 36.1, 36.2, 52.1, 53.1, 54.3, and 55.1.

Staff Expert/Witness: Bret G. Prenger

6. **Variable Costs**

a. Fuel Prices

The Staff computed the fuel expenses for MPS and L&P using prices and quantities incurred by GMO through March 31, 2012. This included using fuel prices for coal, natural gas and oil, including transportation charges in fuel accounts 501 (coal), 547 (natural gas) and 555 (energy portion of purchased power expense).

Staff Expert/Witness: Bret G. Prenger

b. Coal Prices

Staff determined its coal price in the fuel model 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 and or discounts) in effect as of March 31, 2012. Staff plans to review the expenses of supply and freight in its true-up case.

Staff Expert/Witness: Bret G. Prenger

c. Natural Gas Prices

As an input to its production cost model, Staff used the weighted average cost of gas (WACOG) for the period of 12 months ending March 31, 2012. This average includes the variable transportation cost for natural gas, while GMO's natural gas fixed transportation costs are annualized and normalized separately as a part of fuel adders.

Staff Expert/Witness: Bret G. Prenger

d. Oil Prices

Staff used the actual cost GMO paid for its most recent fuel oil purchases at the Montrose generating station to determine variable fuel oil expense. GMO burns oil as a secondary fuel or in some circumstances, for flame stabilization. As a result, GMO purchases fuel oil infrequently. The limited number of fuel oil purchases makes it difficult to employ any type of averaging method. Since purchases aren't routine throughout the year, it is difficult to create a historical analysis. For its direct filed case, Staff recommends using GMO's most recent fuel oil purchase prices at its Montrose Generating Station. These are the best available fuel oil costs to input into the fuel model for determining the variable fuel and purchased power expense on a going forward basis. In discussion with GMO personnel, the Company has not purchased significant quantities of fuel oil for several months at its other generating stations. However, at the time of the true-up in this case, it is expected that significant quantities of fuel oil at its other generating stations will be purchased with differing delivered prices.

Staff Expert/Witness: Bret G. Prenger

7. Spot Market Prices

Spot market purchases are purchases of energy made by a utility on an hourly basis rather than through a long-term contract. A utility decides to buy spot energy based on the economic environment and the availability of its generating units and long-term capacity contract purchases. The purpose of making spot market purchases is to lower overall generation costs when the spot market price is below both the marginal cost of providing that energy from the company's generating units and the utility's firm capacity purchases.

Staff used a procedure developed by the Engineering Section of the Commission's Energy Department and attached here as Appendix 3, Schedule ELM-1, to calculate representative prices for purchased power in the spot market. This method uses a statistical calculation based on the truncated normal distribution curve of hourly data by month to represent the hourly purchased power prices in the spot market for each hour in the test period.

The actual hourly non-contract transaction prices for KCPL and GMO during the year ending March 30, 2012 are the prices used as inputs to Staff's calculation. These prices were obtained from the data that the Company supplied to Staff in compliance with Rule 4 CSR 240-3.190 Reporting Requirements for Electric Utilities and Rural Electric Cooperatives. The calculation yields a spot energy price for each hour of the year. This data set containing 8,760 hourly spot energy prices is then used as one of the inputs to Staff's RealTime® production cost model. These prices may be inflated by the Missouri river flooding conditions which occurred during the summer of 2011. Staff will review spot energy prices through the true-up period ending August 31, 2012 to update the inputs as necessary.

Staff Expert/Witness: Erin L. Maloney

8. Capacity Contract Prices and Energy

Capacity contracts are contracts entered into between electric providers for a specific amount of capacity (megawatts) and a maximum amount of hourly energy (megawatt hours). Prices for the energy from these capacity contracts are based on either a fixed contract price or the generating costs of providing the energy. GMO's capacity contracts include the Gray County Wind Contract, and the Nebraska Public Power District ("NPPD") Cooper Contract.

GMO's actual hourly contract transaction prices were obtained from the data GMO supplied to comply with Rule 4 CSR 240-3.190 and were used by Staff to calculate each contract's average annual generation. Three years of generation data were used to calculate the annual average for the NPPD contract. Because of the variability of the wind generation, seven years of generation data were used to calculate monthly averages for the Gray County Wind Contract. Prices for energy for both contracts are fixed by the contracts.

Staff Expert/Witness: David W. Elliott

9. Planned and Forced Outages

Planned and forced outages are infrequent in occurrence, and variable in duration. In order to capture this variability, the GMO generating unit outages were normalized by averaging the seven years of actual values taken from data supplied by GMO to comply with Rule 4 CSR 240-3.190.

Staff Expert/Witness: David W. Elliott

10. Normalization of Hourly Net System Load

Staff's recommended treatment of determining appropriate fuel and purchase power expenses is to normalize revenues on an annual basis and apply an adjustment factor to each hour of weather-normalized loads to produce the annual requirement of the net system load for usage during the Update Period.[75] Staff's normalization of hourly net system load includes a calculation using separate weather-normalization adjustments for average daily loads and daily peaks. Additionally, Staff normalizes the hourly net system load to determine weather-normalized hourly net system loads that equal the adjusted test year usage, plus losses.

Hourly net system load is the hourly electric supply necessary to meet the energy hourly demands of both the company's customers and the company's own internal needs.[76] Staff calculates an average net system load and an average daily peak load to adjust for fluctuations in energy consumption, where usage may be responsive to differences in factors such as temperatures, seasons, holidays, and times of day.

Weather conditions influence energy consumption. Due to the presence of air conditioning and the presence of significant electric space heating in GMO's service territory,

[75] Update Period: April 1, 2011 through March 31, 2012.

[76] Net system loads are produced to meet the demand requirement for electricity, but the net usage does not include GMO's station use.

the magnitude and shape of GMO's net system input is directly related to daily temperatures. The net-system's reaction to temperature in the MPS rate district differed from the net-system's reaction to temperature in the L&P rate district. Therefore, each rate district was analyzed separately. Actual and normal daily temperatures provided by Staff witness Seoung Joun Won are used in the analysis. The actual daily temperatures during the Update Period 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 total daily energy demand, divided by twenty-four hours. The daily peak load is the maximum hourly energy use, measured for that day. Separate regression models are used to calculate both: 1.) a base component, which is allowed to fluctuate across time; 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 do. 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 is calculated for each day as a function of the actual peak and average loads for that day. 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.[77] The corresponding weather-normalized daily peak and average loads, along with the unitized load curves, are used to calculate weather-normalized hourly loads for each hour of the year.

An adjustment factor is created by dividing the annualized system normalization from the annualized class level normalization. The annualized class normalization is developed after weather-normalizing and annualizing usage for KCPL GMO's retail customer classes is completed for all Missouri and any non-Missouri jurisdictions, weather-normalized wholesale

[77] For more information, the process is described in greater detail in the document, *Weather Normalization of Electric Loads, Part A: Hourly Net System Loads*, (November 28, 1990), written by Dr. Michael Proctor, (then) Manager of the Economic Analysis Department at the Missouri Public Service Commission.

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.

An adjustment factor is then applied 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, and consistent with normalized revenues. Once completed, the test-year hourly normalized system loads were given to Staff witness David Elliott to be used in developing the test year fuel and purchased-power expense. Staff witness Alan Bax also uses the annual requirement of the net system load in developing the Staff's jurisdictional energy allocator.

The Commission should determine the awarded revenue requirement, including Staff's recommended level of ongoing fuel and purchased power expenses, using Staff's methodology of calculating the normalized hourly net system load based upon data from the Update Period.

Staff Expert/Witness: Shawn E. Lange

11. <u>Losses</u>

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

Staff calculates system energy losses as a percentage of NSI, where NSI is equal to the kWh sum of GMO's retail and wholesale sales, plus the electrical energy GMO used in the operation of its facilities (Company Use[78]), plus system energy losses. In other words, NSI = Retail Sales + Wholesale Sales + Company Use + System Energy Losses. This equation may be rearranged to solve for system energy losses as follows:

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

NSI is also equal to the sum of net generation, plus the net of off-system purchases and sales (net interchange). Net generation and net interchange are known quantities as are Retail Sales, Wholesale Sales and Company Use. Therefore, by inputting these components into the

78 "Company Use" does not include station use.

above equation, one can solve for system energy losses. Staff then divides the resulting system energy losses by NSI and multiplies by 100 ((system energy losses/NSI) X 100%) to obtain the system energy losses as a percentage of NSI. This result is referred to as the system energy loss factor, or sometimes called the line loss factor.

Staff has calculated the respective NSI system energy loss factors for the twelve months ending March 2012 of 6.42% for the L&P rate district and 6.64% for the MPS rate district. These system energy loss factors were provided to Staff Witness Shawn E. Lange and used in developing the system loads that are inputted into Staff's fuel model.

Staff Expert/Witness: Alan J. Bax

B. Intra-GMO Allocations

1. Capacity Allocation Between Rate Districts

Staff Recommendations

Staff recommends the Commission assign to the L&P rate district the natural gas-fired 71 MW Ralph Green combustion turbine that was owned by Utilicorp when it was a stand-alone utility. GMO conducts resource planning on a company-wide basis, not on the needs of the MPS and L&P districts. Starting with the addition of 153 MW of Iatan 2 to GMO's rate base in its last general electric rate case, additional capacity is needed to serve customers not only in its MPS rate district, but also in its L&P rate district. The Commission's assignment of 100 MW to MPS and 53 MW to L&P in GMO's last general electric rate case significantly changed the costs assigned to the MPS and L&P rate districts. This recommendation will better align GMO's resources between its MPS and L&P rate districts.

Staff recommends that the Commission order GMO to prepare and file in its next general rate increase case 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.

Resource Assignment Background

The current differing rates and rate structures for the MPS and L&P rate districts originate from the fact that, prior to January 1, 2001, what is now the MPS and L&P rate districts were the Missouri service territories of two separate utilities—UtiliCorp United, Inc. ("UtiliCorp") and St. Joseph Light and Power Company ("SJLP"). When, in Case No.

EM-2000-292, UtiliCorp and SJLP sought authority from the Commission for SJLP to merge into UtiliCorp (renamed "Aquila, Inc." after the merger and "GMO" after Great Plains acquired it in July of 2008), UtiliCorp and SJLP attempted to eliminate any issue of detriment from that case based on rates increasing in the former SJLP by committing to not seek increased rates in the former SJLP service territory based on the merger. As a result, in each of Aquila's and GMO's rate cases since then, the parties have developed revenue requirements and proposed new rates for the two districts based on the plant each owned at the time of that merger—generating plants, transmission systems and distributions systems, etc.—, long-term Purchased Power Agreements each had entered into, and allocations of their common costs such as employee salaries, service centers, etc.

In addition to the rate differential between UtiliCorp and SJLP, the rate structures and rate elements were different for each company. There were even differences in their definitions of customer classes. These different rate structures, rate elements, and customer class definitions remain in the current MPS and L&P rates. For example, the Large General Service Rate for L&P is available for customers with a minimum demand of 40 kilowatts (kW), it contains two hours-use block rates, has a facilities charge and no customer charge. The Large General Service Rate for MPS is available for customers with a minimum demand of 100 kW, has three hours use block rates, no facilities charge but does include a customer charge.

UtiliCorp and SJLP also had different customer bases. UtiliCorp's Missouri customer base was located in the greater Kansas City, Missouri metropolitan area. Most of the large industries in the Kansas City area were in the KCPL service territory; therefore UtiliCorp's customers were mostly weather-sensitive commercial and residential customers. UtiliCorp was summer peaking with relatively flat usage in the non-summer months. SJLP's customer base was a mix of large industrial customers in the St. Joseph area, commercial customers and residential customers. While it was a summer peaking utility, it also had considerable load in the non-summer months. These customer characteristics remain in the MPS and L&P rate districts today.

There was also a difference between the resources each utility had available to meet the requirements of its customers. When UtiliCorp and SJLP merged, SJLP had a peak load of approximately 400 MW that was served with over 300 MW of inexpensive base load generation (Iatan 1 and Lake Road 4) and energy obtained via a very economically advantageous 100 MW capacity purchase agreement ("PPA") with the Nebraska Public Power District (NPPD). UtiliCorp had a peak load three times the size of SJLP (approximately 1200 MW). It relied on base load generation that was more expensive than Iatan 1, a 500 MW PPA with Aquila's Aries natural gas combine cycle merchant plant, and natural gas combustion turbines. When they merged in 2000, both UtiliCorp and SJLP had adequate capacity to meet their customers' needs. In fact, SJLP had enough capacity and energy to serve its customers until the 100 MW long-term PPA with NPPD ended in May 2011. UtiliCorp, on the other hand, needed additional capacity when its PPA with the Aries plant ended in May 2005. Until the last rate case, Case No. ER-2010-0356, the Aries PPA was replaced with the energy from three 105 MW natural gas-fired combustion turbines, a small long-term base load contract with NPPD priced above the SJLP contract with NPPD, and short-term PPAs. The capacity used to serve both the former UtiliCorp and SJLP customers changed significantly in GMO's last general rate case before this Commission, Case ER-2010-0356, and after it, due to the Commission's assignment of Iatan 2 capacity between MPS and L&P, the inclusion of the Crossroads combustion turbines, and the expiration of the SJLP favorable 100 MW NPPD contract.

After UtiliCorp and SJLP merged, Aquila began dispatching to meet the combined load of the L&P and MPS rate districts based on the lowest cost generation or PPA–regardless of which entity had historically owned the generating plant or signed the PPA. These are some of the synergies realized from that merger. When the load in GMO's L&P rate district was less than the SJLP base load capacity, GMO was able to meet the loads of MPS's rate district with the excess low cost base load energy. Similarly when the load in GMO's L&P rate district was peaking in the non-summer months, L&P was able to use the UtiliCorp capacity that was not being used to serve MPS load at that time. GMO's retail customers benefit because, although for ratemaking purposes the costs of the plants and agreements were assigned to MPS and L&P based on whether they had been owned by UtiliCorp or SJLP, these uses of energy for one by generation or purchased power capacity assigned to the other were treated as transfers of power at cost, which resulted in lower fuel and purchased power costs when determining retail customer rates for both the MPS and L&P rate districts.

<u>Impact of Resource Assignments in Case No. ER-2010-0356</u>

In addition to dispatching power on a company-wide basis, since the 2000 merger, GMO has conducted resource planning on a company-wide basis. GMO does not evaluate the needs of its MPS and L&P rate districts separately. This approach, which also leads to merger synergies, did not create ratemaking issues until GMO needed additional capacity for L&P as well as MPS. Until GMO added its 153 MW share of Iatan 2 in 2010, which the Commission included in GMO's rate base in Case No. ER-2010-0356, GMO's capacity was easy to assign to either MPS or L&P, because GMO needed additional capacity for MPS, but not for L&P. Even in that rate case there was no dispute that GMO needed about 300 MW of capacity for MPS apart from Iatan 2, although the parties disputed how to cost that capacity. Ultimately, the Commission decided to include GMO's Crossroads generating station located near Clarksdale, Mississippi, in GMO's rate base for MPS.[79] The assignment of GMO's Iatan 2 costs, because it was now providing GMO's lowest cost energy, between MPS and L&P was hotly contested. Ultimately, the Commission decided to assign them for purposes of setting GMO's rates on the basis of 100 MW of the 153 MW to MPS and 53 of the 153 MW to L&P.[80] Just nine months after Iatan 2 was declared operational and used for service in August 2010, the low-cost, long-term 100 MW NPPD contract that SJLP had been entered into to meet the needs of its customers in and about St. Joseph, Missouri, ended. All together, the effect of Case No. ER-2010-0356 for the summer of 2011 was an increase in GMO's total capacity of 353 MW with MPS receiving and increase in capacity assigned to it of 400 MW (300 MW from Crossroads and 100 MW from Iatan 2) and L&P receiving a decrease in capacity assigned to it of 47 MW (53 MW from Iatan 2 but a decrease of 100 MW due to the end of the 100 MW NPPD contract).

There were consequences to this assignment of Iatan 2 and Crossroads capacity between MPS and L&P. **

[79] *In the Matter of the Application of KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes in its Charges for Electric Service,* Case No. ER-2010-0356, May 4, 2011 *Report and Order.* p. 100.
[80] *In the Matter of the Application of KCP&L Greater Missouri Operations Company for Approval to Make Certain Changes in its Charges for Electric Service,* Case No. ER-2010-0356, May 4, 2011 *Report and Order.* p. 204.

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In effect, on its regulatory books and records for L&P, GMO replaced the low cost NPPD 100 MW contract capacity and energy with 53 MW of Iatan 2 and ** ____ ** The result has been that GMO's books and records reflect higher fuel and purchased power costs for L&P than is appropriate. This is because, in effect GMO has replaced 47 MW of low cost capacity and energy it was getting the 100 MW NPPD contract to meet its needs with ** ____ ** This can be seen in base fuel costs used to set MPS and L&P FAC base factors in GMO's last three rate cases. The base factor for the L&P rate district has *increased* 9.6% while the base factor for the MPS rate district has *decreased* 4.1% from GMO's base factor set in Case No. ER-2007-0004, where the Commission first authorized GMO to use a FAC.

Impact on Fuel Cost Assignments to MPS and L&P Rates

Because the allocated fuel costs were so different for the MPS and L&P rate districts, a separate FAC base factor was derived for each rate district in Case No. ER-2007-0004 based on an annual allocation factor calculated using production cost model runs. Staff and other parties in GMO's rate cases realized that a constant annual allocation factor across all twelve months of the year did not properly allocate fuel and purchased power costs. The single annual allocation factor allocated insufficient fuel and purchased power costs to the MPS rate district in the summer and too much in the other months. Congruently, the single annual allocation factor allocated too much fuel and purchased power cost to the L&P rate district in the summer and not enough in the other months. Therefore, Staff, in Case No. ER-2009-0090 proposed a methodology, which GMO adopted, where, for each hour, GMO's fuel and purchased power costs are allocated to the MPS and L&P rate districts. This allocation methodis based on the idea that GMO must first and foremost use the least expensive resources available assigned to each rate district to serve the retail customers in that rate district ***before*** relying on the least expensive sources available for any additional energy needed, whether that energy be obtained from assets assigned to GMO's other rate district or the spot market. This allocation methodology, which is used monthly to assign actual fuel and purchased power costs to MPS and L&P, while complex, works well as long as the resources assigned to MPS and L&P can easily be identified.

As part of the same company—GMO, neither rate district should be assigned more capacity and energy risk than the other. Ideally Staff would recommend elimination of the assignment of fuel costs between the two and treat them as one for ratemaking purposes. But before treating them as one, GMO should show that the cost and load characteristics that required the continuation of separate rates for the two districts no longer are different enough to keep the two rate districts distinct. The Economic Considerations section of this Staff Report shows that the bill for a typical residential L&P customer is now 6% less than it would be if the customer was charged on the MPS residential rates, which is indicative that GMO's cost to serve customers in the L&P district is approaching GMO's cost to serve customers in its MPS rate district. If the Commission grants GMO's requested increases for MPS and L&P, these bills will move even closer. Similar comparisons of the non-residential class rates are not as easy to show because the rate structures and the rate classifications for MPS and L&P are so different. Staff does not have the information necessary to do similar comparisons for GMO's non-residential customers. Staff recommends that the Commission order GMO to prepare and file in its next general rate increase case 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. GMO should provide a distribution of rate impact on each of its customers of moving from MPS to L&P rate structures and likewise, from L&P to MPS rate structures. If GMO would prefer a rate structure that is different from either MPS or L&P, then individual customer impacts should be provided for the rate structure that GMO proposes. In addition, the Commission should order GMO to do a comprehensive class cost-of-service study to determine the difference in its costs of serving classes of MPS and

L&P customers. Staff will provide more detail for its recommendations regarding MPS and L&P rates in the Rate Design and Class Cost of Service Report it will file on August 21, 2013.

Once this information is provided, a determination can be made regarding treating similar MPS and L&P customers classes on a company-wide basis for ratemaking purposes, which would the eliminate the need for assignment of capacity and fuel costs between the two districts. In this case Staff recommends the Commission address the shortfall in capacity and energy for the L&P rate district that results from the assignment of Crossroads and Iatan 2 in the last case by reassigning from the MPS rate district to the L&P rate district the natural gas-fired 71 MW Ralph Green combustion turbine. Reassignment of this combustion turbine, which went into service in 1981, will minimize the rate impact on GMO's customers in its L&P rate district of the assignment of capacity and energy, while making up for GMO's shortfall in capacity for L&P that results by following the practice of relying on the historical ownership of capacity when assigning and allocating GMO's capacity and energy costs between MPS and L&P. Energy from the Ralph Green combustion turbine plant is more expensive than energy from the 100 MW NPPD long-term contract; however, that contract is over, and Staff and GMO's fuel runs in this rate case show that the energy costs of the Ralph Green combustion turbine is among the lowest of GMO's combustion turbines. Staff's recommendation will not bring the L&P rate district's fuel and purchased power costs down to what they were before the NPPD contract ended, but it would assign to L&P the capacity that it needs rather than ** ______________________________ ______________________________ ** Staff's recommendation would result in the MPS rate district ** ______________________________ ______________________________ ______________________________ ** However, given the relative size of the rate districts, the effect on MPS rates will be much less on MPS than it would be on L&P, and will be offset at least in part by the shift of capital and O&M costs. Ultimately, GMO's retail customers will bear these costs. The issue is what extent will they be borne by its customers in and about St. Joseph, Missouri, or the remainder of its service territory.

Staff Expert/Witness: Lena M. Mantle

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2. **Fuel and Purchased Power Cost Allocation Between Rate Districts**

Staff used the allocation methodology developed in Case No. ER-2009-0090[81], to fairly assign fuel and purchased power costs between the MPS and L&P rate districts. The inputs to Staff's allocation methodology are the hourly normalized loads (net system input) provided by Staff witness, Shawn E. Lange and the hourly output of the RealTime® production cost model (based on those hourly loads) provided by Staff witness David W. Elliott. The output of the RealTime® production cost model is the hourly variable cost of fuel and the purchased power energy costs. The output of the allocation methodology is the assignment of those costs for each rate district for each hour. Staff performed ten iterations of the allocation methodology that correspond to the ten fuel model outputs provided by Staff witness David W. Elliot, eliminated the highest and lowest results and calculated an average annual percentage for the fuel and purchased power costs of each rate district. The results were provided to Staff witness, V. William Harris for use in annualizing fuel expense for the MPS and L&P rate districts.

The allocation methodology assumes that MPS and L&P are each obligated to use the least expensive resources assigned to each rate district, as described by Staff witness Lena M. Mantle in the section of this Report discussing capacity allocations. Specifically, Staff assigned to each rate district the resources that were available to those districts when they were operating as stand-alone utilities except for the capacity allocations outlined in Ms. Mantle's testimony;

- 100 MW of Iatan 2 to MPS
- 53 MW of Iatan 2 to L&P
- 300 MW of Crossroads to MPS
- 71 MW of Ralph Green

Staff determined the percentage of fuel costs incurred by each rate district by making several passes through the hourly data. First, for each hour the energy sources are assigned a rank from least expensive to most expensive. Next, the lowest cost generation available for that rate district is assigned to serve the native load of that rate district. If energy in excess of what

[81] This methodology was adopted in the May 22, 2009 Commission-approved Non-Unanimous Stipulation and Agreement in Case No. ER-2009-0090, and is further explained in Schedule 3 which is attached to that Non-Unanimous Stipulation and Agreement.

was needed was generated by a source, the allocation method stores that information and moves to the next hour. In each hour if energy is still needed to meet the load requirement of a rate district, a decision is made on how to economically meet this need, i.e., where to obtain the least expensive energy. This involves either taking a transfer from the other rate district (excess energy generated) or taking purchased power from the energy market.

Based on the application of this allocation methodology, Staff recommends annual allocation factors for fuel and purchased power costs of 75.72% to MPS and 24.28% to L&P.

Staff Expert/Witness: Erin L. Maloney

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

1. Payroll Costs

Staff recommends allocating payroll costs using KCPL's actual assigned payroll costs for the test year. Staff recommends using actual employee levels as of the update period on March 31, 2012, for annualizing payroll costs, with the exception of the Local 1613 Union employees. Staff has examined the payroll costs of KCPL. All employees of Great Plains Energy are considered employees of KCPL. These KCPL and GPE employees perform all services for Great Plains Energy, KCPL and GMO (including both rate districts, MPS and L&P). An allocation of costs is necessary to assign a proper amount of payroll costs to each of the Great Plains Energy entities and rate districts. Staff has reviewed the allocation of actual assigned payroll costs for each of these entities since the acquisition of the former Aquila Missouri electric operations and allocated the annualized payroll based on this allocation.

The transfer of former Aquila employees was made at the close of the acquisition transaction on July 14, 2008. Because all former Aquila employees providing service to GMO's electric and steam operations became part of the KCPL employee base, KCPL now has to allocate costs directly to each KCPL service territory and the two GMO rate districts, MPS and L&P. Additionally, L&P operations supplies utility services to electric and steam customers and L&P labor costs must be allocated between the electric and steam operations.

Based on the other allocation amounts to the GPE entities, Staff concluded that the actual charged amounts were the best allocation of payroll among KCPL, MPS, and L&P. Staff utilized actual charged amounts to KCPL and the rate districts, net of the joint partners of Wolf Creek and Jeffrey Energy Center charged payroll. The joint partners' costs are amounts charged to

KCPL's partners in the generating assets owned and operated by the Company, with the exception of Wolf Creek Nuclear Operating Corporation, a separate operating company 47.5% of which is owned by KCPL.

Staff annualized payroll costs in this case using actual employee levels as of the update period on March 31, 2012, with the exception of the Local 1613 Union. The union expense was annualized as of April 1, 2012 to incorporate a 3.5% increase in pay. Wages and salaries were applied to each individual employee to compute the total GPE and KCPL payroll costs on an annual basis. Annualized payroll included differential and premium pay, paid to KCPL employees based on union contracts.

As of March 31, 2012, KCPL's holding company, GPE, has a portion of costs that are to be annualized using current employee levels and current salaries. GPE provides common services such as accounting, tax consolidation, corporate legal, and governance to GPE entities. The amount of GPE payroll that relates to KCPL and the GMO entities had to be determined in order to include those costs in the total payroll.

On December 16, 2008, GPE was restructured with all GPE and GPES employees becoming KCPL employees. Because of this restructuring, the allocations factors among KCPL, GMO, and GPE result in GPE having a small portion to account for the above mentioned duties.

Overtime payroll for GMO was calculated using a 3 year average. This particular timeframe was chosen because the overtime hours and sum paid out were reflective of the 3 full calendar years since the acquisition of Aquila, Inc. by GPE. These amounts are specific to MPS, and L&P service territories and, therefore, it is not necessary to include the overtime as part of the allocation process for annualized payroll. The payroll overtime costs have been directly assigned to MPS and L&P.

As the result of KCPL's operating agreements for generating facilities with several partners it is necessary to assign costs to these partners and remove those payroll costs from the payroll annualization that is reflected in the revenue requirement calculations. This assignment of joint partner billings is necessary to ensure that payroll costs properly billed to the joint partners are not included in the KCPL and GMO rate districts' payroll costs. The level of payroll billed by KCPL and GMO to its joint owners in the Iatan and LaCygne generating stations was based upon the March 31, 2012, update period total. Staff used the Company methodology to correctly allocate the reduction in payroll costs from the billing of joint partners, and these costs were removed net of the L&P portion of Iatan before the allocation of payroll to KCPL and GMO. The other payroll costs for partners are billed to The Empire District Electric Company, and the other partners in the Iatan units, and to Westar Energy Company, the 50% partner in the two LaCygne generating facilities.

The total annualized GPE and KCPL payroll costs allocated to GMO also have to be assigned between operational and maintenance ("O&M") expense and other expense. Typically the other expense amount relates to construction and other non-expense functions of a company. The construction amounts are assigned to the work orders for 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.

After the allocation between expense and construction, based on a five-year average expense factor, Staff distributed the adjustment for payroll by individual FERC account based upon the actual distribution for each of those accounts for the update period ending March 31, 2012. L&P Adjustments: E-4.1, 6.1, 20.1, 22.1, 23.1, 39.1, 30.1, 31.1, 33.1, 34.1, 47.1, 48.1, 52.1, 53.2, 54.2, 55.2, 68.1, 69.1, 74.1, 75.1, 76.1, 77.1, 82.1, 88.2, 89.2, 90.2, 92.2, 97.1, 98.1, 99.1, 100.1, 101.1, 102.1, 103.1, 104.1, 105.1, 110.2, 111.2, 112.2, 113.2, 114.2, 115.2, 116.2, 117.2, 118.2, 123.1, 124.1, 125.2, 127.1, 130.1, 131.3, 132.2, 133.1, 136.1, 137.1, 139.1, 143.2, 147.1, 154.2, 155.1, 164.1, 166.1, 167.1, 168.1, 170.1, 171.1 and 176.1. MPS Adjustments: E-4.1, 10.1, 14.1, 15.1, 16.1, 22.1, 23.1, 24.3, 25.1, 26.1, 34.1, 39.1, 41.1, 42.1, 45.1, 46.2, 47.2, 62.1, 63.1, 68.1, 69.1, 70.1, 76.1, 82.2, 83.2, 84.2, 85.2, 86.2, 91.1, 92.1, 93.1, 94.1, 95.1, 97.1, 98.1, 99.1, 103.2, 104.2, 105.2, 160.2, 107.2, 108.2, 109.2, 110.2, 111.2, 115.1, 116.2, 117.2, 119.1, 122.1, 123.3, 124.2, 125.1, 128.1, 129.1, 131.1, 135.1, 138.1, 143.2, 144.1, 147.1, 148.1, 151.1, 152.1, 154.1, 155.1, and 160.1

Staff Expert/Witness: Bret G. Prenger

2. **Payroll Related Benefits**

Staff's annualized 401K expenses were calculated based upon the test year percentage match for GMO and applied to its share of total annualized payroll.

Medical costs and other employee benefits, located in account 926, were calculated based upon twelve months ending March 31, 2012. Other Benefits include items such as Educational Assistance and Recreational Activities. Adjustments to the Income Statement reflect the

calculated payroll related benefits based on payroll costs as of March 31, 2012. L&P Adjustments: E-155.2 and 155.3, and MPS Adjustments: E-144.2 and 144.3.
Staff Expert/Witness: Bret G. Prenger

3. <u>Payroll Taxes</u>

Payroll taxes were annualized by applying current payroll tax rates to each employee's annual level of payroll. To compute payroll taxes for overtime, interns, premium pay, and partner billings, an aggregate tax rate was applied based on the annualized payroll taxes for base payroll. The payroll taxes follow the same allocation process used to allocate base payroll. Adjustments to the Income Statement reflect the annualized payroll taxes based on payroll costs as of March 31, 2012. L&P Adjustments: E-206.1, and MPS Adjustments: E-188.1.
Staff Expert/Witness: Bret G. Prenger

4. <u>True-up of Payroll Costs</u>

Staff will update the total payroll costs for the true-up in this case, which is based on an update period of August 31, 2012. The same methodology used to annualize payroll as of March 31, 2012 will be used for the August 31, 2012 true-up.
Staff Expert/Witness: Bret G. Prenger

5. <u>FAS 87 – Pension Cost – Prepaid Pension Asset – Regulatory Asset</u>

Commission Staff and GMO entered into a Stipulation and Agreement in Case No. ER-2010-0356 (GMO's 2010 rate case) titled, "Second Nonunanimous Stipulation and Agreement Regarding Pensions and Other Post Employment Benefits" (2010 Stipulation). The 2010 Stipulation 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 (FAS) have changed. The Financial Accounting Standards Board's (FASB) Accounting Standards Codification (ASC) project was launched in 2009 and became the single source of authoritative nongovernmental U.S. GAAP (other than guidance issued by the Securities and Exchange Commission). The new Codification Topic 715 covers all of the following FASB statements under its various subtopics:

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

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

MPS Pension

Consistent with the methodology prescribed in the 2010 Stipulation, the Staff has included in MPS rate base the following pension regulatory assets on a Missouri Jurisdictional basis which are being amortized to expense over a five-year period:

Regulatory Asset – ERISA Minimum Tracker	$10,929,980
Regulatory Asset – FAS 87 Pension Tracker	$5,009,564
Regulatory Asset – Prepaid Pension Expense	$13,776,409
Total Pension Compensation Related Assets	$29,715,953

The approximate increase to GMO's revenue requirement resulting from these MPS regulatory pension assets being included in the rate base of MPS is about $3.14 million based on the Staff's proposed capital structure and rate of return. In addition to this return on rate base, the Staff has included as an addition to MPS pension expense $718,242 in pension regulatory asset amortization and an additional $586,751 in FAS 88 amortization. These additions to pension expense are required by the 2010 Stipulation. All of these costs are in addition to the level of annual adjusted pension expense Staff included in its cost of service for MPS of $10,306,667.

Like GMO Staff is proposing cost of service recovery of an allocated share of FAS 88 charges through a five-year amortization increase to pension expense. This FAS 88 charge is related to KCPL's employee termination program referred to as the Organizational Realignment and Voluntary Separation (ORVS) Program. Based on the language related to FAS 88 in the 2010 Stipulation requiring rate treatment of FAS 88 charges, Staff is proposing the same adjustment to the level of FAS 88 costs that GMO is proposing in this case.

The FAS 88 charge is related to the impact on pension expense of 140 employees being removed from KCPL's management pension plan, including the impact of paying lump sum pension distributions. While the FAS 88 charge is an increase to GMO's cost of service, the ongoing level of pension expense should be lower due to the removal of the costs of 140 management employees (total company KCPL) from the pension plan. The Staff is still engaged in discovery to verify the level of pension expense sought by GMO in this case has been decreased by an appropriate amount by the removal of these 140 management employees from the pension plan. The Staff has concerns about the size of the FAS 88 charges and will continue to have discussions with KCPL on this matter and will make its final pension cost rate recommendation in its true-up audit filing after it is convinced that all of the impacts of the ORVS Program have been appropriately and correctly reflected in GMO's cost of service in this case.

MPS has proposed to continue the pension expense methodology used in the 2010 rate case and included in the 2010 Stipulation. This level of expense is based on a twelve-year average of MPS' estimated future share of FAS 87 regulatory expense including the funded status adjustment as calculated by GMO's actuaries, Towers Watson. The Staff believes it is required to continue this pension expense methodology in this current rate case.

Using this methodology, GMO's actuaries calculated an annual MPS pension cost of $10,780,792 before allocation to construction. From this number the Staff applied an adjustment to correct an unreasonably high salary increase assumption used in the the calculation of KCPL's total FAS 87 expense, on which the MPS average FAS 87 expense methodology is based.

There are a number of assumptions built into Towers Watson's quantification of GMO's pension expense that were supplied to it by KCPL's management. One of these assumptions is projected level of future annual salary increases for current company employees (all employees are KCPL employees; GMO has no employees) in the pension plan. The salary increase assumption is important because KCPL's current level of pension expense is based in part on a projection of future salary levels for its employees. A higher salary increase assumption will lead to a higher pension liability and a higher pension expense.

The annual salary increase assumption selected by KCPL management for KCPL's current projected pension expense is 4.0% for its management plan and 4.25% for its union pension plan. The Staff has concerns that given the economic environment over the past three years and continuing into the foreseeable future, this assumption actually overstates the level of pension expense that should be reflected in this rate case. Based on a review of the current salary increase assumptions used by all major regulated utilities in Missouri, the Staff's concerns were confirmed.

The Staff reviewed the most recent annual reports of all major Missouri regulated utilities and noted that KCPL's salary assumption rates of 4% and 4.25% are the highest of all Missouri utilities and significantly higher than the all Missouri utility average of 3.25 percent. The utilities reviewed were Ameren Missouri, The Empire District Electric Company (Empire), Laclede Gas Company (Laclede), American Water Works Company, Inc. ("American Water" - parent company of Missouri-American Water Company) and Southern Union Company (parent company of Missouri Gas Energy). The results of Staff's analysis are summarized below:

Company	Salary increase assumption (%)
Laclede	3.00
Southern Union Company	3.02
American Water	3.25
Ameren Missouri	3.50
Empire	3.50
Average	3.25
KCPL (management and union)	4.00/4.25

KCPL's salary increase assumptions are the highest of all major regulated utilities in Missouri. To reflect the impact on pension expense of a salary increase assumption more in line with other Missouri utilities, the Staff adjusted KCPL's annualized pension expense by reflecting a 3.5% in lieu of a 4% and 4.25% salary increase assumption. The numerical support for the amount of the adjustment was provided by KCPL's actuaries in response to Staff Data Request No. 246S in Case No. ER-2012-0174, KCPL's current rate case.

In addition to the Staff's analysis of KCPL's salary increase assumption used in the calculation of pension expense as compared to other large Missouri utilities, the Staff also reviewed the actual salary increase percentage paid by KCPL to its management and union workers over the past five years (2008-2012). This review further supports Staff's conclusion that the 4% and 4.25% rates selected by KCPL management in determining pension expense is unreasonably high.

L&P Pension

Staff has included in L&P's rate base the following pension regulatory assets on a Missouri Jurisdictional basis which are being amortized to expense over a five-year period:

Regulatory Asset – ERISA Minimum Tracker	$1,675,535
Regulatory Asset – FAS 87 Pension Tracker	$ 337,405
Regulatory Asset – Prepaid Pension Expense	$3,684,792
Total Pension Compensation Related Assets	$5,697,732

The approximate increase to revenue requirement resulting from these L&P regulatory pension assets being included in rate base is approximately $602,000 based on the Staff's proposed capital structure and rate of return. In addition to this return on rate base, the Staff has included as an adder to L&P's pension expense $52,961 in pension regulatory asset amortization and $225,251 in FAS 88 amortization as required by the 2010 Stipulation. All these costs are in addition to the level of annual pension expense Staff included in cost of service for L&P of $2,687,415 (after a $4 million funded status adjustment reduction in expense). This amount is also stated after the Staff's salary assumption adjustment described above.

Staff Expert/Witness: Charles R. Hyneman

6. FAS 106 – Other Postretirement Benefit Costs (OPEBs) and OPEB Tracker Regulatory Liability

Other Postretirement Benefit Costs ("OPEBs") are those costs incurred by the Company to provide certain benefits to Company retirees. The primary benefit to retirees is medical insurance but also includes life, dental and vision insurance benefits. Historically OPEB costs have been calculated by KCPL's actuaries under the terms of Financial Accounting Standard 106 (FAS 106). Recently, ASC 715, the Accounting Standards Codification Topic, Compensation-Retirement Benefits, superseded FAS 87, FAS 106, FAS 132 and FAS 158. ASC 715 reflects current generally accepted accounting principles ("GAAP") which outlines the standards of financial accounting and reporting for employers that offer pension and other postretirement benefits to employees. For purposes of clarity and continuity with the ratemaking treatment afforded KCPL's OPEB costs over the years, in this testimony I will use the term FAS 106 synonymously with the term ASC 715 as they both encompass the same accrual accounting methods for determining OPEB expense.

FAS 106 is the Financial Accounting Standards Board ("FASB") approved accrual accounting method used for financial statement recognition of annual OPEB costs. The accounting the cost of postretirement benefits is not based on the actual dollars KCPL pays for OPEBs to its retirees currently; instead 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 benefits earned in the current year, before an employee's retirement when the benefits are paid, and the interest cost arising from the passage of time until those benefits are paid.

The Staff's OPEB adjustment to GMO Account 926, Employee Benefits annualizes the level of OPEB expense determined by GMO's actuaries using the FAS 106 accounting. If more current OPEB actuarial reports for KCPL's Management and Union OPEB plan are completed prior to the end of the true-up period in this case, Staff will update its OPEB expense annualization accordingly. Staff adjusts GMO's September 2011 ending test year per book costs for FAS 106 to reflect the more current FAS 106 actuarial calculation for 2012.

Beginning June 25, 2011, GMO initiated a new tracker for OPEB costs for its MPS and L&P districts. This OPEB tracker was authorized by the Commission in the Stipulation and Agreement in Case No. ER-2010-0356 (2010 rate case) titled, "Second Nonunanimous Stipulation and Agreement Regarding Pensions and Other Post Employment Benefits," (2010 Stipulation). The dollars tracked are the difference between the current ongoing level of OPEB expense and the dollar amount of OPEB 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 added to or subtracted from the level of OPEB expense as determined by the actuaries. As with other rate base prepaid pension and other pension assets, it is anticipated that the OPEB tracker liability will be updated through the August 31, 2012, true-up period.

Staff Expert/Witness: Charles R. Hyneman

7. <u>Supplemental Executive Retirement Plan (SERP) Expense</u>

A SERP is an additional executive pension compensation program which provides benefits to highly-compensated employees over and above the benefits provided under the "all-employee" regular pension plan. SERP's exist because the Internal Revenue Code ("IRC") does not permit a tax deduction for pension expense above certain dollar amount for employees who are considered highly compensated. Companies create a SERP to provide highly-compensated employees pension benefits over and above the amount that the IRC allows as a reasonable business deduction.

GMO is seeking rate recovery of SERP costs allocated from KCPL to GMO. This SERP allocation is in substance compensation for utility service provided by KCPL's former executive-level employees (now retired) to KCPL prior to any affiliation between KCPL and GMO. GMO was acquired by Great Plains Energy in July 2008; none of the retired former KCPL executives who are receiving SERP ever provided any service to GMO, before or afer the acquisition. As such, charging GMO ratepayers for benefits (employee utility service) they never received is inappropriate and the Staff's proposed level of SERP expense for GMO does not include this KCPL allocation of KCPL SERP expense.

MPS SERP

Included in the Staff's revenue requirement recommendation for MPS is the test-year amount of recurring (non lump-sum) SERP payments made by MPS to its former executive and other highly-compensated employees as appropriately adjusted and allocated to MPS by the Staff.

MPS capitalizes a portion of its SERP expense for MPS to capital projects, such as regulatory assets and construction work-in-progress. The Staff does not believe that SERP payments should be capitalized in a manner similar to normal pension expense. The SERP payments are made to former employees who provide no current or future value to the utility's operations or the construction of capital assets. Therefore, all of the payments, to the extent that they are reasonable and prudently incurred, should be charged to expense.

The Staff's SERP adjustment for MPS is based on the actual recurring payments made, as shown in GMO's proposed SERP adjustment workpaper entitled CS-26. In that workpaper MPS listed each former executive who receives a SERP payment and the amount of the monthly SERP payment. However, it does not appear that GMO made any attempt to allocate any of the total SERP payments to MPS that is representative of the level of service these former Aquila executives provided to Missouri regulated operations.

For example, in rate cases prior to its acquisition by Great Plains Energy, Aquila, Inc. allocated only approximately 20 percent of the payroll and other costs of the Chief Administrative Officer to MPS. In its adjustment in this rate case, GMO is allocating

100 percent of the SERP payments related to this position to Missouri regulated operations. Staff's adjustment allocates the appropriate amount of SERP expense for each former Aquila executive based on service these former executive-level employees provided to Missouri regulated operations while in the employ of Aquila.

The Staff also made an adjustment to reduce the amount of annual recurring SERP payments made to two former Aquila executives to approximately $50,000 per year. Payments to former executives of $50,000 per year, in addition to normal pension retirement payments, are a ceiling for what Staff considers to be reasonable SERP payments. This reasonableness ceiling was established based on Staff's experience with other utility SERP payments over several years and was applied by Staff in prior Aquila rate cases. The Staff believes any recurring SERP payment to former Aquila executives above this amount is excessive and should not be included in GMO's cost of service.

Finally, in Aquila's past rate cases, the Staff took issue with the fact that a significant level of Aquila's SERP expense was based on compensation received as bonus payments and incentive compensation that was not included in cost of service. To prevent SERP expense based on non-regulated compensation from being included in its adjustment, the Staff reduced each former employee's SERP payment by 20 percent prior to allocation to Missouri regulated operations. The 20 percent is an estimate of the amount of annual recurring SERP expense that is based on non-regulated compensation.

Because of SERP's unique nature and the fact that the benefit represents an additional executive pension benefit over and above what is already provided in the regular pension plan, the Staff treats SERP costs somewhat differently from normal employee pension costs.

The Staff's policy has been and continues to be recommend that SERP costs be included in cost of service if such costs are not significant, are reasonably provided for, and can be quantified under the known and measurable standard. MPS' annual recurring SERP payments as adjusted by Staff in this case meet these tests.

L&P SERP

The Staff's L&P SERP adjustment Staff removes all SERP expenses booked in the test year to L&P's income statement. L&P is seeking rate recovery of SERP costs allocated from KCPL related to the service KCPL's former executive-level employees (now retired) provided to

KCPL. As described above, this allocation is inappropriate as those L&P customers have never received any benefit from the employee service being compensated through a SERP.

Similarly, the Staff did not allocate any of the SERP expense for the former Aquila executives to L&P. Shortly after the Commission issued a Report and Order in Case No. EM-2000-0292 on December 14, 2000 that authorized UtiliCorp and SJLP to merge, they merged and renamed the surviving corporation Aquila. Since all or nearly all of the former Aquila executives provided most of their service to Aquila prior to the merger, the Staff determined that these former Aquila employees provided little or no benefit to GMO's customers in the L&P rate district. Because no benefit was provided, any allocation of the compensation related to the utility service provided by these former Aquila executives would be inappropriate.

Staff Expert/Witness: Charles R. Hyneman

8. March 2010 Organizational Realignment/Voluntary Separation (ORVS) Program

KCPL launched its Organizational Realignment/Voluntary Separation Program ("ORVS") on March 10, 2011. Under this voluntary separation program, any KCPL non-union employee could voluntarily elect to separate from KCPL and receive a severance payment equal to two weeks of salary for every year of employment, with a minimum severance payment equal to fourteen weeks of salary.

There were 140 KCPL employees that made such elections, and the majority separated from KCPL on April 30, 2011. KCPL recorded an expense of $12.7 million related to this voluntary separation program, reflecting severance benefits and related payroll taxes provided by KCPL to employees who elected to voluntarily separate from KCPL and allocated a pro rata share of this expense to MPS and L&P.

At page 94 of KCPL's 2011 SEC Form 10-K, KCPL stated that the savings from the realignment process and voluntary separation program included $15 million in labor costs on an annual basis. Staff did an analysis of the net costs of the ORVS program (including KCPL's FAS 88 costs) and the net savings realized through regulatory lag. Staff's analysis shows that KCPL recovered all of its ORVS-related costs (including amounts allocated to MPS and L&P) and realized a net savings of approximately $13 million (total savings allocated on a KCPL jurisdictional basis). The Staff's analysis was based on actual data provided by KCPL, including employee salaries and current benefit-salary ratios.

In its response to Staff Data Request No. 119 in Case No. ER-2012-0174, KCPL recognized that it will recover in rates in just one year more than the total cost of the ORVS Program through regulatory lag as follows:

> As seen in the attachment, the total of the annual salaries of the employees electing the program was over $12.5 million. If we applied a conservative benefits loading rate of 40%, the annual savings from the terminating employees would reach $17.5 million. With the total cost of the program near $13 million, the Company should begin to achieve savings in the first quarter of 2012.

It is clear by even KCPL's own admission that it has recovered all of its ORVS costs and more through regulatory lag. Regulatory lag is a naturally occurring phenomenon in cost of service regulation. It refers to the period of time between when a cost or revenue changes and the time that change is reflected in rates. Immediately after MPS and L&P's last rate case, Case No. ER-2010-0356, KCPL announced the employee reduction program – after ensuring the salaries and benefits of the future severed employees would be captured in MPS and L&P's rates going forward.

Staff made the same adjustments as proposed by MPS and L&P to remove the test year amount of ORVS severance program cost from the test year books and records. However, since these employee severance costs have been recovered in rates, Staff is not recognizing this ORVS cost as a deferral and is not reflecting any amortization of this cost in its MPS or L&P revenue requirement recommendations. It is inappropriate ratemaking theory to defer and seek rate recovery of a cost that has already been directly recovered in past utility rates.

FAS 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*, (now classified as part of ASC 715, Compensation-Retirement Benefits) addresses the accounting for settlements and curtailments related to pension benefits. As noted above, the Staff performed an analysis of the level of savings enjoyed by KCPL by continuing to recover all ORVS-related costs in rates from April 30, 2011 through February 2, 2013 (the date when rates from this case will take effect). Staff's analysis confirmed that KCPL will recover all of its ORVS-related costs, including all FAS 88 costs, through regulatory lag and still receive substantial savings. However, because of the language of the *Second Nonunanimous Stipulation and Agreement Regarding Pensions and Other Post*

Employment Benefits in Case No. ER-2010-0356 (2010 Stipulation), Staff is including the amount of KCPL's ORVS FAS 88 KCPL allocated to MPS and L&P as an additional pension expense charge in this rate case. Paragraph 43b of the 2010 Stipulation states that all of GMO's FAS 88 pension costs related to GMO Missouri jurisdictional electric operations, inclusive of amounts allocated to GMO as a joint-owner of the Iatan generating units/stations, subsequent to December 31, 2010 will be deferred in a regulatory asset by jurisdiction and amortized to cost-of-service over five years in the next MPS and L&P rate cases.

Staff Expert/Witness: Charles R. Hyneman

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

KCPL has three separate, short-term annual incentive compensation plans for executive, management, and 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 based 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 three incentive compensation plans are: 1) the Rewards Plan, reserved for bargaining-unit (union) employees; 2) the Value-Link Plan, reserved for management-level KCPL employees; and 3) the Annual Executive Incentive Plan, reserved for senior KCPL management employees.

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

The Rewards Plan was implemented to reward bargaining-unit employees for their efforts in supporting the objectives of the Company. The purpose of the plan is to provide an incentive for the achievement of defined annual results of KCPL and its divisions (Accounting, Regulatory, Finance, Human Resources, etc.). The plan covers bargaining-unit employees from the International Brotherhood of Electrical Workers ("IBEW") Local 1464 (approximately 659 employees), Local 412 (approximately 847 employees), and Local 1613 (approximately 420 part/full time employees). ** ____

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Staff does not oppose incentive compensation paid under the Rewards Plan, as the KCPL Rewards Plan scorecard goals include customer metrics and are primarily customer focused. The Rewards Plan is not the result of a collective bargaining agreement. If it were the result of a collective bargaining agreement, then it is my understanding that pursuant to Section 386.315.1 RSMo., in establishing public utility rates, the Commission is prohibited from reducing or otherwise changing any wage rate, working condition, or other term or condition of employment that is the subject of a collective bargaining agreement between a public utility and a labor organization.

The Value-Link Plan was implemented to provide an incentive for the achievement of defined annual results of the Company (KCPL) and its business units by management-level KCPL employees, such as Plant Manager or Insurance Manager. **

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The Commission has historically disallowed the awarding of incentive compensation tied to the utility achieving certain corporate financial measures on the basis that these measures provide no tangible benefit to Missouri ratepayers. *See* specifically *Re KCPL*, Case Nos. ER-2006-0314, 15 Mo. P.S.C. 3d 138, 171-72 (2006) and *Re KCPL*, ER-2007-0291, pp. 49-51 (2007). However, since the conclusion of Case No. ER-2009-0089, KCPL has revised its Rewards, Value-Link and Executive Incentive Compensation Plans and has removed all thresholds dealing with financial metrics, i.e., Earnings per Share (EPS). After reviewing the Value-Link Plan, Staff is not proposing to exclude amounts actually paid out under the Value-Link Plan established by the revised plan.

The third short-term annual incentive plan is the Annual Executive Incentive Plan ("Executive 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 GPE and KCPL management. **

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L&P Adjustments E-4.2, 74.2, 89.3, 97.2, 100.2, 101.2, 105.3, 113.3, 123.2, 133.3 and 143.5, MPS Adjustments E-4.2, 68.2, 91.2, 94.2, 99.2, 106.3, 115.2, 125.2 and 135.2.

Staff Expert/Witness: Bret G. Prenger

10. <u>Long-Term Incentive Compensation</u>

According to GPE, the purpose of the GPE Long-Term Incentive Plan is to encourage officers and other key employees to acquire a proprietary and vested interest in the growth and performance of GPE; to generate an increased incentive to enhance the value of the Company for the benefit of its customers and shareholders; and to aid in the attraction and retention of the qualified individuals upon whom the Company's success largely depends. ** ____________

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GMO proposed to remove the costs from the Long-Term Incentive Compensation Plan for its officers in File No. ER-2012-0174 via Company 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: Bret G. Prenger

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, transmission and distribution network of the electric system, and the general plant. Specific types of maintenance work tied to specific classes of plant are listed in functional maintenance expense accounts in the FERC 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 March 31, 2012, by functional area for production, transmission, distribution, and general plant by FERC account. Staff separated maintenance between labor and non-labor costs. Since labor costs are specifically addressed as a component in the cost of service analysis, labor costs were segregated from the non-labor costs to perform the review of maintenance costs. Staff annualized payroll reflecting the price increases for labor that generally occurs each year. A detail of Staff's position related to payroll is located under the heading *Payroll, Payroll Related Benefits* in this report. The maintenance analysis was done only on non-wage maintenance and operating costs.

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 the Staff, was to compare functional averages which included using a two (2)-year average through a seven (7)-year average to determine if there were fluctuations with each functional area. Staff also analyzed Production maintenance excluding Iatan 2 production maintenance. The purpose of excluding Iatan 2 production maintenance costs is to identify if production maintenance fluctuated absent these costs. Staff performs a separate analysis for Iatan 2 production maintenance. A discussion for Iatan 2 production maintenance is located under the heading *Iatan 2 O&M Expenses* in this report. Each of the costs by year and averages for maintenance were also compared to the Test Year, 12-month period ended September 30, 2011. Staff reviewed the data as detailed above to establish a maintenance level that will result in an annual level of the Company's future maintenance costs.

Staff's results are presented in the following table:

Results of Staff's Non-Labor Maintenance Analysis		
	MPS	L&P
Steam Production Maintenance	Test Year 12-Month Ended September 30, 2011	Test Year 12-Month Ended September 30, 2011
Other Production Maintenance	2-year average (2010-2011)	2-year average (2010-2011)
Transmission Maintenance	2-year average (2010-2011)	4-year average (2008-2011)
Distribution Maintenance	3-year average (2009-2011)	2-year average (2010-2011)
General Maintenance	2-year average (2010-2011)	Test Year 12-Month Ended September 30, 2011

As identified in the table above, Staff made a decision to use the 12-month period ended September 30, 2011 test year account balances to represent future maintenance costs for Production Maintenance for MPS and L&P. Staff used the 12-month period ended September 30, 2011 test year to reflect a level of normalized maintenance for these costs based on actual information provided by GMO for a period of several years. This historical information was analyzed to determine the proper level of maintenance which should be included in this case. Fluctuations occurred each year for Other Production, Transmission, Distribution and General Maintenance. Consequently, for MPS a two (2)-year average of Other Production, Transmission and General and a three (3)-year average of Distribution Maintenance reflects a normal level of maintenance expense that should be included in MPS's cost of service. The adjustments included in Staff's Accounting Schedule 9 for MPS Other Production are E-45.1, E-46.1, E-47.1 and E-48.1; Transmission adjustments are E-82.1, E-83.1, E-84.1, E-85.1 and E-86.1; Distribution adjustments are E-103.1, E-104.1, E-105.1, E-106.1, E-107.1, E-108.1, E-109.1, E-110.1 and E-111.1. For L&P a two (2)-year average of Other Production and Distribution and a four (4)-year average of Transmission Maintenance reflects a normal level of maintenance expense that should be included in L&P's cost of service. The adjustments included in Staff's Accounting Schedule 9 for L&P for Other Production are E-53.1, E-54.1, and E-55.1; Transmission adjustments are E-87.1, E-88.1, E-89.1, E-90.1, E-91.1 and E-92.1; Distribution adjustments are E-110.1, E-111.1, E-112.1, E-113.1, E-114.1, E-115.1, E-116.1, E-117.1 and E-118.1.

Staff Expert/Witness: Karen Lyons

1. **Iatan 2 O&M Expenses**

Staff included an annualized level of Iatan 2 O&M expenses and an amortization of the costs in excess of the base amount established in Case No ER-2010-0356. In Case No ER-2010-0356, Staff recommended a tracker for Iatan 2 O&M expense, so the actual cost of the O&M expense related to Iatan 2 will be recovered through rates for both the rate payer and GMO in future rate cases. Since Iatan 2 was placed in service on August 26, 2010, and GMO's limited operational experience with Iatan 2 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 will in all likelihood vary from the actual costs associated with Iatan 2's O&M expense. GMO and other signatory parties agreed through a Stipulation and Agreement in Case No. ER-2010-0356 to establish a tracker for Iatan 2 costs and on May 4, 2011, the Commission approved the use of a tracker for these costs.

In this case, Staff analyzed Iatan 2 O&M costs beginning August 26, 2010, through April 2012. Staff included an annualized level of expense for Iatan 2 O&M for the 12 month period of April 2012. GMO advised Staff of an accounting error that occurred with the Iatan 2 and Common costs that was corrected in March 2012. Since the correction was made in March 2012, the update period in this case, Staff chose to include an annualized level of Iatan 2 costs consisting of the 12-month period ended April 2012 and will examine these costs again for the true up period of August 31, 2012. The annualized level of Iatan 2 O&M costs for MPS are reflected in Accounting Schedule, Adjustments: E-4.3, E-14.2, E-15.2, E-16.2, E-17.1, E-22.2, E-23.2, E-24.1, E-25.2, E-26.2, E-137.7 and for L&P the adjustments are E-4.3, E-20.2, E-22.2, E-23.2, E-24.1, E-29.2, E-30.2, E-31.2, E-33.2, E-34.2, E-146.8. In addition to determining an ongoing level of Iatan 2 O&M expenses, Staff is proposing the recovery of the excess costs over the base amount established in the Stipulation and Agreement in Case No ER-2010-0356. Staff is proposing a three (3)-year amortization of the excess costs over the base amount. For MPS adjustments reflecting one-third of the total costs are reflected in Staff's Accounting Schedule 9, Adjustments E-4.4, E-14.3, E-15.3, E-16.3, E-17.2, E-22.3, E-23.3, E-24.2, E-25.3, E-26.3, E-137.8 and for L&P the adjustments are E-4.4, E-20.3, E-22.3, E-23.3, E-24.2, E-29.3, E-30.3, E-31.3, E-33.3, E-34.3, E-146.9.

As previously mentioned, Iatan 2 was placed in service on August 26, 2010. At the end of the true up period in this case, August, 31, 2012, the plant will have operated for two (2) years. Since the plant is still in its early stage of operation, two (2) years is not an adequate period of time to recommend an annualized level of O&M expense for a new coal fired power plant. Therefore, Staff recommends the continuation of the Iatan 2 tracker at the annualized level discussed above.

Staff Expert/Witness: Karen Lyons

E. Other Non-Labor Adjustments

1. Bad Debt Expense

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 MPS and L&P are 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 MPS and L&P are subsequently able to successfully collect some portion of previously written off delinquent amounts owed, then those amounts collected reduce the actual write-offs. This results in the net write-offs which are used to determine the annualized levels of bad debt expense for MPS and L&P.

Staff calculated the annualized bad debt expense by examining the billed revenues, net of gross receipt taxes for the twelve months period ending September 30, 2011, and actual 12-month history of billed revenues that were never collected (actual net write-offs) for the twelve months ending March 31, 2012. From this information a bad debt ratio was derived, which was then applied to Staff's annualized level of retail revenues for MPS and L&P to obtain the annualized levels of bad debt expense for each rate district. The apparent lag time between the net retail sales and actual net write-offs in Staff's calculation is consistent with MPS's and L&P's positions on how bad debt write-offs are accounted.

MPS and L&P assert 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. Adjustment E-118.1 in Staff's Accounting Schedule 9 reflects an annualized level of bad debt expense for MPS, and Adjustment E-126.1 reflects an annualized level of bad debt expense for L&P.

Staff Expert/Witness: Karen Lyons

2. Outsourced Meter Reading

Prior to this case, GMO contracted with a third party to perform meter reading service in the MPS rate district. After GMO's direct filing and before the March 31, 2012 update period, GMO hired meter readers to replace the need for outsourced meter reading in the MPS rate district. Staff included the employee additions in its payroll annualization discussed in the *Payroll, Payroll Related Benefits* in this Report. Consequently, Staff made an adjustment to remove the costs booked during the test year ending September 30, 2011. Staff's adjustment is reflected in Account Schedule 9, Adjustment E-116.1.

Staff Expert/Witness: Karen Lyons

3. **Advertising Expense**

In forming its recommendation of the allowable level of advertising expense, Staff relied on the principles the Commission followed as a result of the 1986 Kansas City Power & Light rate case, (Case No. EO-2005-0329 beginning with the 2006 rate case, Case No. ER-2006-0314). In Re: Kansas City Power and Light Company, 28 MO P.S.C. (N.S.) 228 (1986) (KCPL), the Commission adopted an approach that classifies advertisements into five categories and provides separate rate treatment for each category. The five categories of advertisements recognized by the Commission are:

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

The Commission adopted these categories of advertisements because 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)). The purpose of Staff's review of KCPL's advertising costs was to ensure that only advertising costs for programs necessary for the provision of safe and adequate utility service are included in the MPS and L&P's cost of service. For example, all costs for safety advertising and indirectly related to safety advertising were included as well as other costs necessary for GMO to communicate with its customers on utility matters. Staff removed test year expenses incurred by GMO for advertising programs that are appropriately classified as institutional image in nature.

Staff has come to the conclusion to make adjustments to account 908.000 and 909.000, as well as pick up the Company adjustments to account 930.100. Finally, Staff chose to pick up the Company adjustments for account 930.1, that simply reflect the change between test year and known and measurable.

Staff focused on campaigns, not individual advertisements, which is consistent with the Commission's discussion on the topic as stated in its rate case order, the AmerenUE *Report and Order* in ER-2008-0318. L&P Adjustments E-131.6, 132.4 and 171.2 MPS Adjustments E-123.4, 124.3, and 155.2.

Staff Expert/Witness: Bret G. Prenger

4. 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 included all dues payments made by GMO to each area's Chamber of Commerce, but removed the state-level Chamber of Commerce. Allowing Chamber fees for individual cities or the state-level Chamber, but not both, is consistent with how Staff has treated Chamber fees for utility companies in past cases. Staff removed all other dues as costs not necessarily in the provision of utility service. The adjustment was made to GMO in account 930.2. In addition to this adjustment, Staff removed costs in which it considers the expenses to be personal or of no benefit to the ratepayer and thus, not included in a utility's cost of service. L&P Adjustment E-170.5 and MPS Adjustment E-154.2.

Staff Expert/Witness: Bret G. Prenger

5. Miscellaneous Test Year Adjustments

a. GMO Adjustment CS-11

In its direct filing, GMO included Adjustment CS-11 which includes several categories of miscellaneous adjustments totaling a reduction of $2,373,932 for MPS and $818,040 for L&P to their test year costs of service. There are several categories within the total adjustment:

A. Correct expense report items to below-the-line

1. This adjustment removes test year expenses related to a board of directors retreat, board of directors transportation, and other items that KCPL proposes to charge below the line.

2.

B. Correct lobbying costs in activity EX023 to below-the-line

3. This adjustment removes test year expenses related to lobbying that KCPL proposes to charge below the line.

4.

C. Rate Case Items

5. This adjustment has several sections:
    1. Removal of a portion of nextSource rate case expenses pursuant to the Commission's order in Case No. ER-2010-0355.
    2. Removal of over-amortization of KCPL rate case expenses from Case No. ER-2007-0004.
    3. Removal of additional nextSource rate case expenses incurred post-true up in Case No. ER-2010-0356.
    4. Establish a regulatory liability for rent abatement.
    5. Establish a regulatory asset to defer DSM advertising costs related to the Connections Program and amortize over 10 years.
    6.

D. Legal Fees

7. This adjustment removes test year expenses related to the sale of former Aquila Headquarters at 20 W 9th and other legal expenses.

8.

E. Outside Services

9. This adjustment removes test year expenses for financial advisory services and consulting expenses.

10.

F. Test Year Adjustments

11. This adjustment removes all test year expenses related to KCPL's Long Term Incentive plan allocated to GMO. This adjustment is addressed by Staff Expert Bret G. Prenger in the "Long Term Incentive Compensation" section of this Staff Cost of Service Report.

12.

G. Special Bonus and Severance Payments

13. This adjustment removes test year spousal travel, ad hoc bonuses, and severance payments for former executives.

14.

H. Miscellaneous Coding Corrections

15. These adjustments are miscellaneous accounting coding corrections.

Staff has reflected these adjustments to the test year cost of service for KCPL as MPS Adjustments E-137.2, E-63.2, E-125.3, E-137.4, E-149.1, E-149.2, E-149.3, E-149.4, E-156.4, E-123.5, E-124.4, E-140.1, E-140.2, E-76.2, E-84.3, E-94.3, E-95.2, E-95.3, E-97.2, E-99.4, E-105.3, E-106.4, E-106.5, E-108.3, E-109.3, E-109.4, E-116.3, E-135.4, E-137.5, E-140.3, E-154.4, E-154.5, E-156.3, E-160.2, E-135.5, E-137.6, E-154.7, E-143.3, and E-156.5.

Staff has reflected these adjustments to the test year cost of service for KCPL as L&P Adjustments E-146.4, E-69.2, E-133.2, E-146.5, E-164.2, E-164.3, E-164.4, E-164.5, E-172.1, E-131.5, E-132.3, E-149.1, E-143.3, E-170.3, E-143.4, E-146.6, E-170.4, E-154.3, and E-172.2.

Staff Expert/Witness: Keith Majors

6. Debit/Credit Card Acceptance Program

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 by registering on GMO website. Payment through the website offers two options one time payments or 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 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 associated with the credit and debit card program based upon the total card level and per unit transaction cost as of the test year, twelve-month period ended September 30, 2011, to represent an ongoing level of costs. Staff will review these costs through the true up period, August 31, 2012 and make any necessary adjustments.

Staff Expert/Witness: Karen Lyons

7. Accounts Receivable Bank Fees

The selling of accounts receivable results in the Company collecting revenues on an accelerated basis from the lending institution. The adjustment for bank fees relates to the costs of selling the accounts receivable. The benefit to the company is that it receives enhancement to its cash management. For rate making purposes this enhancement is reflected in the acceleration of the collection process, identified through a shorter revenue lag in the CWC schedule, than otherwise would have occurred absent the sale of the accounts receivable.

GMO was formed subsequent to GPE's acquisition of Aquila, Inc. in 2008. Aquila had established an accounts receivable sales program with Ciesco, an affiliate of Citibank. The program involved a loan from a third party backed by MPS and L&P accounts receivable. When Aquila began to experience a severe decline in its credit rating, Ciesco terminated the program. The termination of the accounts receivable sales program was the direct result of the Company's poor financial condition and has caused a detriment to MPS and L&P ratepayers. The loss of the sale of the accounts receivables resulted directly from the problems that Aquila faced in its non-regulated ventures.

In 2009, GMO began negotiations with account securitization facilities to establish an accounts receivable sales contract. GMO was unable to establish a contract because it did not have at least three years of standalone post-acquisition accounts receivable data available.

As previously mentioned, when GMO filed its current case in February 2012 it did not have an accounts receivable sales program in place. 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." Consequently, GMO annualized its projected fees, including interest, as if the accounts receivable sales program were already in place. Effective May 31, 2012, GMO, GMO Receivables Company, The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch, as agent, and Victory Receivables Corporation entered into a Receivables Sale Agreement.

Staff has reflected GMO's projected annualized fees, with interest, through the period ended March 31, 2012 in Adjustment E-127.2 (L&P) and Adjustment E-119.2 (MPS). Staff will annualize GMO's actual accounts receivable bank fees through August 31, 2012 in its true-up filing.

Staff Expert/Witness: V. William Harris

8. Lease Expense

Lease costs are those costs incurred by KCPL for the leasing of its corporate headquarters. Staff examined these costs for the test year ending September 30, 2011 and updated them through March 31, 2012. KCPL moved its corporate headquarters to One Kansas City Place, 1200 Main Street, Kansas City, MO during the fourth quarter of 2009.

Staff 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 has to pay other costs for customer and employee parking, as well as the annual costs for the building's electricity and an additional rent portion in the agreement for additional space when needed. KCPL currently rents four classifications of parking spaces: Visitor, Reserved, High Profile Vehicles, and Unreserved. To calculate an annualized amount for parking, Staff took the number of spaces provided in each category, except for visitor parking which is based upon Company estimates, and multiplied by the monthly rate, then applied that total multiplied by 12 months. Also, Staff picked up the adjustments of the Company to back out amounts that were associated with other standard parking accounts, so as to avoid double-counting this expense. KCPL pays electricity at a rate per square foot leased for the building. Once the portions of the lease expense are totaled (base rent, parking, and electricity, additional rent) those amounts are then allocated between KCPL, GMO, and GPE using the Massachusetts formula calculated by the Company.

When KCPL relocated to the new location, it was allowed 270 days (9 months) of rent free time, called an abatement period. Staff calculated an adjustment to reflect the "free rent" over a 5 year timeframe, and adjusted it out of the test year lease expense. The calculation of this adjustment was handled in a very similar manner to the corporate headquarters lease adjustment. Staff took the base rent and parking expenses and instead of annualizing them for a full 12 months, multiplied it by a 9-month period. A similar allocation as to that used for the annualized lease expense is also calculated for the abatement period savings, with the costs being allocated between KCPL and the GMO rate districts.

Staff's adjustments to Lease Expense can be identified as L&P Adjustments E-105.4, 146.7, 148.1, 172.3, 172.4, 172.5, 176.2 MPS Adjustments E-156.1 and 156.2.

Staff Expert/Witness: Bret G. Prenger

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 is amortized to expense ratably over the life of the insurance, by annualizing the level of insurance expense and allocating an appropriate portion of GMO's insurance expense to GMO's Cost of Service. Insurance expense is the cost of protection obtained from third parties by utilities against the risk of financial loss associated with unanticipated events or occurrences. Utilities, like non-regulated entities, routinely incur insurance expense in order to minimize their liability associated with unanticipated losses for property assets and personal injury from accidents. Certain forms of insurance reduce ratepayer's exposure to risk. Premiums for insurance are normally pre-paid by utilities; i.e., payment is made by the utility to the insurance vendor in advance of the policy going into effect. These insurance payments are normally treated as prepayments, with the amount of the premium being booked as an asset and amortized to expense ratably over the life of the period the insurance is in force. The unamortized balance of the prepaid insurance account (either the period-ending balance or a 13-month average balance) is included in rate base, with an annualized level of insurance expense included in rates.

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

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

Staff reviewed the policies and verified the current insurance premiums for each insurance type. An annualized amount was determined and allocated to MPS and L&P and reflected in their Cost of Service. KCPL renewed several insurance policies in May 2012. As part of its true-up audit, Staff will review these policies and recommend any necessary adjustments to the amounts allocated to MPS and L&P in this case. The same methodology used to annualize Insurance Expense as of March 31, 2012, will be used to annualize Insurance Expense for August 31, 2012. The Commission should base its awarded revenue requirement on an annualized level of Insurance Expense. The annualized levels for GMO's portion of the insurance costs are reflected in Adjustments E-142.1 and E-143.4 for MPS and Adjustments E-153.1 and E- 154.4 for L&P.

Staff Expert/Witness: Patricia Gaskins

10. <u>Injuries and Damages</u>

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 five years of data and determined a three-year average, including the period of 2009 through 2011, using the actual cash payments to normalize GMO's costs associated with injuries and damages. The actual cash payments are those paid to individuals who had an injury and claim. As a result of these injuries, GMO made cash settlements. A three-year average was used based on the data received from GMO. This normalization of known and measurable changes of the actual cash payments over a multi-year period is the appropriate method that the Commission should use in the ratemaking process and is consistent with GMO's method to normalize injuries and damages in its rate case.

Staff's methodology uses historical actual cash payment amounts to calculate the normalized level of expense and Staff's method is the same method used by GMO in this rate case. The Commission should base its awarded revenue requirement on Staff's recommended normalized level of expenses associated with injuries and damages, which Staff calculates using known and measurable actual cash payments made, to determine the appropriate level of expense. For MPS Adjustment E-143.1 and for L&P Adjustment E-154.1 reflect a normalized level of costs for injuries and damages.

Staff Expert/Witness: Patricia Gaskins

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

Staff's recommended treatment of Property Tax Expense is to annualize property tax expenses based upon property GMO had in-service on January 1, 2012, by multiplying that property amount to Staff's property tax ratio derived from 2011 tax payments. Staff adjusted test year property tax expense in order to include in rates the annualized level of 2012 property taxes. Each year GMO is billed 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 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 ending September 30, 2011, updated through March 31, 2012. Since the update period in this case is March 31, 2012, Staff determined the annualized property taxes based on the property GMO had in-service on January 1, 2012. Staff applied a property tax ratio based on actual 2011 property tax payments to January 1, 2011, plant. This ratio of property taxes when applied to the January 1, 2012, plant provides the amount of property taxes expected to be paid for 2012. Because the test year in this case is September 30, 2011, property tax expenses for 2012 was annualized as of the January 1, 2012 date. This calculation is an estimate of the total 2012 property tax expense. Both Staff and GMO typically accomplished this by looking to the tax rate paid for the previous year, and then applying it to the property owned at the start of the current year.

For the current rate case, Staff obtained from GMO the total amount of taxable property owned on January 1, 2012, and then applied to it the tax rate assessed to GMO in 2011. The property tax rate assessed in 2011 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, 2011. Any required payments in lieu of taxes ("PILOTs") applicable to non-taxable property were added to the total estimated tax for 2012. Staff recommends this method of calculation as providing the best available information, since it relies on the actual January 1, 2012, balance of GMO's property, and uses the most recent, known tax rate (2011), without attempting to estimate any change in the rate of taxation for 2012 that is not known as of the update period March 31, 2012. Staff's approach is consistent with that taken previously and received several favorable rulings from the Commission in prior cases, most recently in KCPL 2006 rate case. In its *Report and Order* issued in Case No. ER-2006-0314 the Commission stated the following:

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

Based on the methodology addressed earlier, Staff made an adjustment to include an annualized amount for property taxes. The Commission should base its awarded revenue requirement on Staff's 2011 property tax ratio applied to the total amount of taxable property GMO owned on January 1, 2012. For MPS Adjustment E-184.4 and for L&P Adjustment E-204.1 reflect the annualized levels for property tax.

Staff Expert/Witness: Patricia Gaskins

12. <u>Rate Case Expense</u>

Staff recommends the Commission include a normalized level of rate case expense in GMO's revenue requirement used for setting rates in this case, except for the rate case expenses GMO incurred during KCPL's Regulatory Plan, which are subject to deferral and amortization.

Staff adjusted GMO's post-true-up 2010 Rate Case expense allocable to Missouri (post December 31, 2010) from $1,230,865 to $835,428 for MPS and $247,167 to $123,336 for L&P to account for the reimbursement of rate case expense GMO received from Empire, then Staff further adjusted it to $459,103 for MPS and $17,387 for L&P based on disallowing costs GMO incurred post December 31, 2010, for (1) Schiff Hardin personnel who did not testify at the evidentiary hearing during the 2010 Rate Case — a disallowance of $358,577 for MPS and $102,451 for L&P, (2) SNR Denton's defense in the 2010 Rate Case of KCPL's actions regarding the Iatan 2 Advanced Coal Tax Credit—a disallowance of $5,506 for MPS and (3) The Communication Counsel of America's witness development and coaching services — a disallowance of $12,242 for MPS and $3,498 for L&P. Like GMO, Staff did not include NextSource costs related to Chris Giles in GMO's post-true-up rate case expense.

Staff disallowed the non-witness Schiff Hardin personnel costs from GMO's rate case expense because the number of personnel for the services rendered was excessive, their rates were high and GMO's post true-up 2010 rate case expense is excessive and unreasonable. Staff's support for these rationales follows. Staff included in rate case expense the costs for the services of Schiff Hardin personnel and others who testified and whose services were billed to GMO through Schiff Hardin—Mr. Roberts, Daniel F. Meyer, Steven Jones and Jim Wilson.

As explained below, Staff disallowed the outside litigation counsel SNR Denton fees and expenses associated with KCPL's defense of its actions regarding the Iatan 2 Advanced Coal Tax Credit because those actions were imprudent, KCPL was not justified in employing outside counsel for this issue and, therefore, none of GMO's retail customers should bear any responsibility for these fees and expenses.

Consistent with how the Commission disallowed The Communication Counsel of America witness development and coaching services costs in GMO's 2010 Rate Case, Staff disallowed The Communication Counsel of America witness development and coaching services costs GMO incurred post the December 31, 2010, true-up cut-off date in its 2010 Rate Case.

In the KCPL and GMO 2010 Rate Cases, the Commission found in Findings of Fact 495 that KCPL and GMO made no adjustments or corrections to any of Schiff Hardin's bills for legal services or any experts' invoices. To date, KCPL and GMO have yet to identify any adjustment made by any law firm vendor.

Background

Rate case expenses are costs a utility incurs in preparing and executing the filing of its rate case. In the instant case, GMO has incurred rate case expenses for outside legal counsel, temporary labor, and outside consultants.

Generally, Staff treats rate case expense as an expense necessary to providing utility service and includes in the utility's revenue requirement a normalized level of rate case expense based on the rate case expenses the utility has incurred in the past. After determining the normalized level Staff divides it over the period of time it estimates will pass before the next rate case and includes an annual amount of the normalized level in the utility's revenue requirement. Under a normalization approach to rate recovery of rate case expense, this cost is not "amortized" for ratemaking purposes, and the company's recovery of this expense in rates is not tracked against its actual rate case expense amounts. However, because KCPL'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 those rate cases—Case Nos. ER-2006-0314 ("2006 Rate Case"), ER-2007-0291 ("2007 Rate Case"), ER-2009-0089 ("2009 Rate Case") and ER-2010-0355 ("2010 Rate Case"). After GMO became an affiliate of KCPL in 2008, Staff deferred and amortized its rate case expenses, separately for MPS and L&P, in GMO's next two rate cases, Case Nos. ER-2009-0090 and ER-2010-0356. For the remaining rate case expenses for each of these cases, as adjusted, Staff used a "defer and amortize" approach to calculate the associated revenue requirements to be included in the following rate case. However, because the four Regulatory Plan rate cases are completed, Staff is returning to its typical normalization approach for establishing an ongoing level of rate case expense to include in the MPS and L&P revenue requirements in this case, *i.e.*, Staff is not proposing GMO be allowed to defer and amortize any rate case expenses incurred for this instant case.

While the "tracker," or "defer and amortize" method utilized during KCPL's Regulatory Plan results in the exact amount of rate case expense recovered in rates, there is a distinct disincentive to adequately and prudently manage expenses. On the other hand, using a normalized level of costs incents the utility to actively manage costs for efficient operations, similar to a variety of other expenses Staff normalizes.

<u>Use of Defer and Amortize Procedure</u>

Under the defer and amortize approach to rate case expense, for each rate case, GMO's rate case expenses incurred for that rate case after the true-up cut-off date in the case were a separate vintage deferral. Each of those vintage deferrals was amortized over an appropriate time and an annual amount of the amortized level included in the revenue requirement for GMO's next rate case. For this case Staff is including in the MPS and L&P revenue requirements an annual amount of amortization of the last of the GMO rate cases associated with KCPL Regulatory Plan rate case expense vintage deferrals. In practice, these back-to-back amortizations have functioned much like the trackers the Commission has authorized for vegetation management and pension expenses.

In the April 4, 2009, *Non-Unanimous Stipulation and Agreement* the Commission approved and ordered the signatories' to carry out their agreement that any over recovery of the amortization of KCPL's rate case expense in the 2006 Rate Case would be used to offset the amount of rate case expense incurred and deferred in the 2009 Rate Case. This application of over-recovered expenses, while not an approach that would be used under normal ratemaking circumstances, is consistent with the "defer and amortize" approach, which is functionally similar to tracker accounting. For the cases brought during KCPL's Regulatory Plan, Staff has continued this rate case tracker approach and applied the over recovery of rate case expense from GMO's 2007 Rate Case against GMO's rate case expense deferral in its 2009 Rate Case, and applied the over recovery of rate case expense from GMO's 2009 Rate Case against GMO's rate case expense deferral in the 2010 Rate Case.

In GMO's 2010 Rate Case, Staff included the expenses GMO incurred after the true-up cut-off date of its 2009 Rate Case, and the expenses GMO incurred related to the April 2010 proceedings concerning Staff's Iatan Construction Audit and Prudence Review in File No. EO-2010-0259, with the rate case expenses in GMO's 2010 Rate Case incurred through December 31, 2010. Consistent with its approach in GMO's 2010 Rate Case, Staff again aggregated the requested 2010 Rate Case expense for recovery under the defer and amortize approach. The rate case expenses requested for recovery through December 31, 2010 in the 2010 KCPL and GMO Rate Cases, including 2009 Rate Case post-true-up expenses, are shown in the below table:

Rate Case Expenses Requested in 2010 Rate Cases	
Company/District	Total
KCPL - MO	$4,593,427
MPS	$2,001,855
L&P	$1,175,870
Total Though 12/31/2010	$7,771,152

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Most of the rate case expense amounts subject to the deferral and amortization treatment have either been agreed to or ordered in prior rate cases. However, there is a portion of rate case expense relating to GMO's 2010 Rate Case that GMO incurred after the true-up cut-off date in that case and which the Commission has ordered to also be given deferral and amortization treatment. In the Commission's *Report and Order* in the 2010 Rate Case, the Commission specifically ordered on Page 187 the deferral of post-true-up rate case expenses as follows:

> The amounts allowed and disallowed represent the true-up amounts recorded as of December 31, 2010, and are not final rate case expenses. Rate case expenses for these cases after the true-up will be deferred for possible recovery in the next rate case, subject to review for prudence and reasonableness.

KCPL's and GMO's rate case expenses paid after December 31, 2010 in the 2010 Rate Cases are shown in the below table. The sharing of rate case expenses with Empire is also shown:

Additional Expenses from 2010 Rate Cases Post True-Up

Company/District	Total Incurred	Empire Shared Expenses	Net Incurred
KCPL - MO	$2,605,670	($650,473)	$1,955,197
MPS	$1,230,865	($395,437)	$835,428
L&P	$247,167	($123,831)	$123,336
Total Expense	$4,083,702	($1,169,741)	$2,913,961

For comparison, the total rate case expenses incurred in KCPL's 2010 Rate Case and GMO's 20120 Rate Case of $11,854,854, and $10,685,113, respectively, net of Empire shared expenses and including their 2009 Rate Case post-true-up rate case expenses and the expense associated with File No. EO-2010-0259, are shown in the below table:

Total Incurred Rate Case Expenses – 2010 Rate Cases			
Company/District	Total Incurred	Empire Shared Expenses	Net Incurred
KCPL - MO	$7,199,097	($650,473)	$6,548,624
MPS	$3,232,720	($395,437)	$2,837,283
L&P	$1,423,037	($123,831)	$1,299,206
Total Rate Case Expenses	$11,854,854	($1,169,741)	$10,685,113

To give the Commission a perspective of the increasing rate case expenses, the table below details the total incurred rate case expenses from the prior three rate cases for KCPL and, GMO:

Rate Case Expenses for 2005-2009 Rate Cases				
Total Costs	KCPL - MO	GMO - MPS	GMO - L&P	Total
2005/2006 Rate Cases	1,400,291	345,365	110,021	1,855,677
2007 Rate Cases	715,349	520,253	130,063	1,365,666
2009 Rate Case	2,171,609	468,928	445,079	3,085,616
3 Case Average	1,429,083	444,849	228,388	2,102,320

KCPL and GMO's projected rate case expenses for the 2012 Rate Cases from KCPL and GMO's direct filing are detailed below:

KCPL March 31, 2012 Rate Case Expenses and Total Projected 2012 Rate Case Expenses				
	KCPL - MO	GMO - MPS	GMO - L&P	Total
2012 Rate Case Through March 31	224,006	83,184	61,503	$368,693
2012 Projected - KCPL Workpaper	2,019,535	1,099,357	388,959	$3,507,851

Staff made the adjustments to GMO's post-true-up 2010 Rate Case expense that are explained in detail in the sections below.

Adjustments to Amounts to Be Deferred and Amortized

Schiff Hardin Rate Case Expense Adjustment

In the 2010 Rate Cases, KCPL and GMO incurred a total of $7.7 million of combined rate case expense as detailed in the table in the section above. Of that total, Schiff Hardin expenses totaled $1.3 million through the true-up in those cases, prior to any expenses related to hearings. These amounts are charged to rate case expense, and do not include any Schiff Hardin charges capitalized to the Iatan Construction Project:

Schiff Hardin Rate Case Expenses Currently in the Cost of Service	
Schiff Hardin Rate Case Expenses	December 2010 True Up Cutoff
KCPL - MO	$988,496
MPS	$275,291
L&P	$89,130
Total	$1,352,917

Including the amounts paid after the true-up in the 2010 Rate Cases, the total paid to Schiff Hardin charged to rate case expense was $3,534,400:

Total Schiff Hardin costs charged to 2010 Rate Case Expenses			
Schiff Hardin Rate Case Expenses	December 2010 True Up Cutoff	Post December 2010	Total
KCPL-MO	988,496	1,003,482	1,991,978
MPS	275,291	916,223	1,191,514
L&P	89,130	261,778	350,908
Total	1,352,917	2,181,483	3,534,400

KCPL provided a description of the duties Schiff Hardin performed in the 2010 Rate Cases in Tim Rush's true-up rebuttal testimony in Case No. ER-2010-0355 (Exhibit No. KCP&L 115) on page 6 as follows:

Schiff Hardin assisted in testimony preparation, coordination of prudence strategy, document analysis and review, preparation of exhibits, legal research regarding prudence analysis of prior MPSC disallowances, cross examination preparation, and issue identification.

KCPL and GMO incurred significant rate case expenses from Schiff Hardin after the December 31, 2010 true-up in the 2010 Rate Cases. The total Schiff Hardin post-true-up expenses, by invoice, are shown in the table below:

Post-True-Up Schiff Hardin Invoices	
Schiff Hardin Invoice No.	Total
1555304	$343,135
1544353	$437,149
1567750	$415,721
1577839	$147,535
1582954	$22,583
1594314	$4,466
1555941	$810,895
Total	$2,181,483

A portion of those rate case expenses were borne by Empire, as previously discussed in this report. The rate case expenses, net of Empire's share, are shown below:

Empire Reimbursement of Schiff Hardin Expenses				
Schiff Hardin Post True-up	% Charged	Total	Less: Empire Sharing	Net Expense
KCPL - MO	46%	$1,003,482	($198,389)	$805,093
MPS	42%	$916,223	($162,241)	$753,982
L&P	12%	$261,778	($22,880)	$238,898
Total	100%	$2,181,483	($383,510)	$1,797,973

A summary of the total Schiff Hardin billings by employee timekeeper, hourly rate, expenses, client adjustments, and discounts is shown in the highly confidential table below:

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	Total Hours	Hourly Rate	Total Billings

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Of the 11 (eleven) employee timekeepers from Schiff Hardin above, the only individual appearing as a witness in the 2010 Rate Cases, and the consolidated hearing for ER-2010-0356, was Kenneth M. Roberts. Neither Mr. Roberts nor any of the other Schiff Hardin employees entered appearances as attorneys of record in the 2010 Rate Cases.

KCPL and GMO witnesses Daniel F. Meyer and Steven Jones were billed through Schiff Hardin, and their expenses are included in the "Disbursements" line item of the table above. This line item also includes billing hours from support staff, invoices from Jim Wilson and Associates, and travel expenses related to the Schiff Hardin timekeepers.

As Mr. Rush described Schiff Hardin's role in the 2010 Rate Cases, Schiff Hardin provided much of the litigation support during the hearings in the 2010 Rate Cases. These are duties that are often performed, or could have been performed, by KCPL in-house counsel, KCPL in-house support staff, or the other legal vendors KCPL and GMO retained for the 2010 Rate Cases, vendors such as SNR Denton, Fischer & Dority, Stinson Morrison & Hecker, and The Cafer Law Office, all of whom billed rate case expenses in the 2010 Rate Cases.

As of December 31, 2010, the annualized payroll utilized by Staff in its true up case included 20 (twenty) individuals employed by KCPL licensed to practice law in the State of Missouri. GMO has no employees; KCPL personnel perform GMO's work and allocate appropriate labor to GMO. Of those in the Law, Regulatory, and General Counsel departments, the average hourly rate with benefits as of December 31, 2010 was ** __ **, as opposed to the significantly higher hourly rates KCPL paid for legal services in the 2010 Rate Cases. The hourly and annual rates paid by KCPL, and consequently ratepayers, as of the 2010 Rate Case true-up and Staff's March 31, 2012 update in the 2012 Rate Case appear in the tables below[82]:

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[82] The benefits rate of 0.61, or 61% of the hourly rate, was utilized as an estimate by KCPL in its Adjustment CS-49, Distribution Intelligence and Tech Support ("DFITS") as supported by KCPL witness William Herdegen, an adjustment unrelated to rate case expense. Staff is utilizing this rate only as an estimate for comparison purposes, not as a representation of actual expenses.

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Not only are these rates substantially lower than KCPL's various external counsel, the fully allocated cost of these employees is being paid and will be paid by KCPL's and GMO's ratepayers. Considering the hours billed by Schiff Hardin detailed above, other than amounts billed by Mr. Roberts, KCPL paid for the equivalent of nearly 4 (four) KCPL in-house attorneys *for an entire year* ** — **. This comparison considers only one legal vendor, it does not take into account expenses from The Cafer Law Office, Duane Morris, Fischer & Dority, Morgan Lewis & Bockius, Polsinelli Shalton Flanigan Suelthaus, Skadden Arps Slate Meagher & Flom, SNR Denton, Spencer Fane Britt & Browne, and Stinston Morrison & Hecker, all of whom billed KCPL and GMO for 2010 Rate Case legal expenses.

The Commission, on Page 179 of its 2010 GMO Rate Case *Report and Order*, recognized that KCPL in prior cases had utilized in-house attorneys:

> 496. In its last litigated rate case, KCP&L in-house attorneys shared in a great deal of the work associated with litigating that case. Those attorneys, whose salary and benefits are already recovered through rates, litigated issues associated with policy, off-system sales margins, Hawthorn 5 settlement costs and uranium enrichment overcharges. [footnote omitted]

The Commission, in its 2010 GMO Rate Case *Report and Order* was presented with and ordered adjustments to rate case expense concerning NextSource expenses and The Communication Counsel of America (CCA) expenses. Particularly, the Commission found on Page 186 of its *Report and Order* that the services provided could have been performed by in-house attorneys:

> …The CCA provided witness development and coaching services, routine tasks typically performed by retained counsel, internal or otherwise. The KCC also disallowed similar expenses as unjust and unreasonable. The Commission determines that the CCA expense should be disallowed as duplicative of other services that were performed or should have been performed [sic] KCPL's and GMO's attorneys.

For the same reasons the Commission disallowed the CCA expenses, the Staff recommends disallowance of all Schiff Hardin non-witness expenses.[84]

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[83] ** ______________________________ **

[84] Mr. Roberts was the sole employee witness provided by Schiff Hardin. Daniel Meyer and Steven Jones also appeared as witnesses but are not employed by Schiff Hardin.

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As identified by KCPL witness Tim Rush in the 2010 Rate Case, the Schiff Hardin non-witness expenses related to "testimony preparation, coordination of prudence strategy, document analysis and review, preparation of exhibits, legal research regarding prudence, analysis of prior MPSC disallowances, cross examination preparation, and issue identification." These are activities that are reasonably expected of KCPL in-house attorneys and staff, at a substantially discounted rate.

To compute Staff's adjustment, Staff identified all charges not related to Mr. Roberts, Daniel F. Meyer, and Steven Jones, who were KCPL witnesses billed through Schiff Hardin in the 2010 Rate Case. Staff did not adjust hourly billings or expenses related to these individuals. Staff did not remove charges related to Jim Wilson of Jim Wilson & Associates, who provided scheduling expertise related to the Iatan Project, and was not directly involved in preparation or execution of the 2010 Rate Case hearings. Staff identified travel expenses not related to these individuals for its recommended adjustment. The total adjustment is detailed below. The amounts have been adjusted for the Empire sharing of rate case expenses:

. **Staff Recommended Schiff Hardin Adjustment**	
Schiff Hardin Expense Category	Amount
Hourly Fees	1,070,178
Disbursements	70,250
Less Empire Share	(286,673)
Total Adjustment	$853,755

Allocation	Total	$853,755
KCPL - MO	46%	$392,727
MPS	42%	$358,577
L&P	12%	$102,451

Failure to Contain Costs

During the hearings in the 2010 Rate Cases, the Commission asked several questions of KCPL and GMO's policy witness concerning expenses from Schiff Hardin:

Commissioner Kenney:

Q. Okay. Was there ever a time when you objected to Shiff [sic] Hardin's bills and asked them to make adjustments?

KCPL Witness Blanc:

A. No. There were times that I would talk to the people who were working closely with them and make sure the type of work they were describing, just to verify what was going on, so I questioned. But did I ever challenge in the sense of ask them for a deduction; no. I never asked or a deduction or recommended a deduction would have been my role. [sic]

(Case Nos. ER-2010-0355 and ER-2010-0356, Vol. 14, Tr. 267, l. 6-15)

In the next day of hearings, KCPL's witness was further cross–examined on Schiff expenses:

Jaime Ott:

Q. Did you ever have a dispute with Schiff Hardin on the amount of work that they were billing to you?

KCPL Witness Blanc:

A. No. As I said, we had those discussions, but there was never an unresolved issue. I was always comfortable with the explanation of -- or we were comfortable, I should say, the law department, Jerry Reynolds and I were comfortable that they were doing the work they said they were doing and their work was productive. They weren't wasting time doing it.

Q. So none of your conversations with Mr. Reynolds or in the law department ever led you to contact somebody at Schiff Hardin to question—

A. Not --

Q. -- a particular item on the invoice?

A. Not that I'm aware of. I never did.

(Case Nos. ER-2010-0355 and ER-2010-0356, Vol. 15, Tr. 500, l. 13 to Tr. 501 l. 3.)

Jaime Ott:

Q. And that's at risk of getting into highly confidential number -- it's not. So -- you have paid over 20 million just for Schiff?

KCPL Witness Blanc:

A. That's correct. In the broad support for the projects over the past five years, that's correct. And it's less than 1 percent of the project cost.

(Case Nos. ER-2010-0355 and ER-2010-0356, Vol. 15, Tr. 503 ll. 1-6.)

Commissioner Gunn had several questions for KCPL's policy witness Blanc:

Commissioner Gunn:

Q. Was there any adjustment to rates to reflect Kansas City rates or were they Chicago rates, do you know?

KCPL Witness Blanc:

A. I would say they were neither. They were construction expert rates, geographic -- geographically irrelevant.

(Case Nos. ER-2010-0355 and ER-2010-0356, Vol. 15, Tr. 534, ll. 4-9)

Commissioner Gunn:

Q. We're talking about $20 million. Ultimately you guys paid this law firm $20 million for the services that they were doing?

KCPL Witness Blanc:

A. Yeah. And --

Q. And there was no -- Let me finish the question.

A. You bet.

Q. There -- there doesn't appear to be any negotiation on rates, there doesn't appear to be any negotiation on volume discount. You knew how long the project was going to last. There had to be a budget put together for what you were going to pay this entity. And you guys just picked who you thought won it. Now, I'm not saying that was a bad choice, but I just want to make it -- asking the clear questions.

You did not try to negotiate down rates, you did not try to get other firms that -- in -- and there was no competitive process in order to hire the firms. And so let me -- I'll ask that question. There was no competitive process to hire this firm and there was no appearance to negotiate lower rates based on either geographic location or other competitive factors?

A. They're just going to have to parse out what I know and I don't know. I do know there was not an RFP process, but because I wasn't involved directly in hiring them or negotiating, I don't know any discussions around discounted rates. I don't know that. But I do know that they didn't charge us for any of their travel time.

(Case Nos. ER-2010-0355 and ER-2010-0356, Vol. 15, Tr. 535 l. 7 to Tr. 536, l. 12.)

Commissioner Gunn:

Q. And there was not a single time entry in that entire $20 million -- or approximately $20 million that was ever disallowed?

KCPL Witness Blanc:

> A. No. There were ones that arose questions, but those questions were always addressed.

(Case Nos. ER-2010-0355 and ER-2010-0356, Vol. 15, Tr. 538, ll. 2-6.)

Commissioner Gunn:

> Q. And -- and these are fees that you are -- that are separate from rate case expense. Right? These will be included in project cost? These would not be considered rate case expense. Correct?

KCPL Witness Blanc:

> A. The vast majority. There would be a very small portion that they've done in support of the rate cases, but that would be an extremely small portion of that number.

(Case Nos. ER-2010-0355 and ER-2010-0356, Vol. 15, Tr. 539, ll. 2-9.)

Throughout the cross-examination, KCPL's witness could not identify any adjustments KCPL made to any of the legal billings of $20 million of Schiff Hardin expenses. There was no objection to bills, no billing disputes, and no negotiation of fees.

Clearly, in comparison to the approximately $20 million Schiff Hardin charged to the Iatan Construction Project, the $3.5 million charged to rate case expense was not "an extremely small portion of that number."

In its 2010 GMO Rate Case *Report and Order,* the Commission stated on page 185:

> Although the Commission acknowledges the complexity and significance of these rate cases, the Commission is concerned with the continued increase of rate case expenses. It is undisputable that shareholders benefit from hiring the very best advocates and experts. This clearly aids in their ability to argue for a higher return on equity as well as the recovery of a greater percentage of costs. Yet, given the magnitude of these expenses ($7.7 million dollars), with substantially more to be deferred to the next case, the Commission would expect to see some evidence that KCP&L and GMO had engaged in cost containment. Mr. Blanc, however, testified that of the invoices received for legal fees and expert consultants not one was questioned by the Companies.

Despite this admonition by the Commission in the last rate case, GMO continues to fail to closely manage its rate case expenses. The Commission, in its Report and Order, clearly expected GMO to engage in cost containment and management of rate case expenses. However, Staff has yet to see, other than $13,621 in client adjustments and discounts in the invoices above, of any kind of management of rate case expenses. In response to Staff's Data Request 128, Case No. ER-2012-0174, KCPL could not identify any billing adjustment by a legal vendor. Staff's request with KCPL's response follows:

> Question No.: 0128
>
> Provide each and every billing adjustment by a law firm vendor charged to rate case expense in 2009, 2010, and 2011.
>
> Response:
>
> Discounts may be noted on bills previously produced to Staff that fall within the aforementioned timeframe in Case Nos. ER-2010-0355, ER-2010-0356, and EO-2010-0259. See list of prior DRs below containing that information:

EO-2010-0259	Data Request 415.1RS
EO-2010-0259	Data Request 415.1RS2
ER-2010-0355	Data Request 141.2
ER-2010-0355	Data Request 141.3S
ER-2010-0355	Data Request 141.3RS
ER-2010-0355	Data Request 593S
ER-2010-0356	Data Request 154.2S
ER-2010-0356	Data Request 154.2TS

> For bills that have not been previously produced to Staff there are no adjustments made by law firm vendors.
>
> The Company is unaware of any adjustments made by law firm vendors prior to receipt. It is customary practice for law firm vendors to perform an internal review of invoices prior to submission to the client. Therefore, adjustments may have been made without the Company's knowledge prior to delivery to the Company for review and payment.

GMO's reliance on legal vendors to manage the expenses billed by those vendors is not in keeping with the direction the Commission provided to KCPL and GMO in their 2010 rate cases. Staff is aware of the pendency of Case No. AW-2011-0330 (*In the Matter of a Working File to Consider Changes to Commission Rules and Practices Regarding Rate Case Expense)*, and ongoing consideration of rate case expense management. Staff, however, is not recommending a specific disallowance solely as a consequence of GMO's failure to challenge legal invoices.

Qualifying Advanced Coal Project Credit Litigation Expenses charged to Rate Case Expense

KCPL and GMO incurred external legal fees in their 2010 Rate Cases from vendor SNR Denton in defending the issues surrounding the Qualifying Advanced Coal Project Credit. GMO and KCPL chose not to employ in-house counsel to litigate this issue, the costs of who were already in KCPL's and GMO's revenue requirements. The matter of the Qualifying Advanced Coal Project Credit is discussed in more detail in this report by Staff Expert Cary G. Featherstone in that section. GMO ratepayers in MPS should not bear the incremental costs related to KCPL's and GMO's defense of the imprudent decisions related to this issue. Staff has identified the specific hours related to the research, litigation, and briefing of the Qualifying Advanced Coal Project Credit issue before the Commission. Staff removed the attorney fees for these hours from GMO's rate case expense for MPS as they are a direct result of KCPL's and GMO's imprudent decisions. Staff removed these fees from the post true-up rate case expense from GMO's 2010 Rate Case. If the Commission does not adopt Staff's normalized level of rate case expense, Staff recommends removal of any similar fees from GMO's 2012 Rate Case expense and from any amounts deferred for future recovery. The rate case expense legal fees from vendor SNR Denton charged to KCPL and GMO specifically related to the Qualifying Advanced Coal Project Credit are shown in the below table:

KCPL – MO	$15,365
GMO – MPS	$5,506
Total	$20,871

In the current 2012 Rate Case, KCPL and GMO have hired PricewaterhouseCoopers, LLP (PwC) as a consultant and witness on their Qualifying Advanced Coal Project Credit issues. According to KCPL's response to Staff Data Request 299 in Case No. ER-2012-0174, through May 2012, KCPL incurred $20,700 of expenses related to its witness Salvatore Montalbano of PwC and another PwC employee, Bob Hriszko, both of which are billed to KCPL at $600 per hour, the highest hourly rate of any consultant or attorney utilized by KCPL or GMO in the current rate cases. Mr. Montalbano's fees were charged directly to KCPL's rate case expense.

Because KCPL incurred these expenses only because its employees neither informed GMO of nor sought for GMO a portion of the tax credit before KCPL's and GMO's 2010 rate cases, Staff disallowed from KCPL's rate case expense the expenses KCPL has incurred by retaining PwC for its Qualifying Advanced Coal Project Credit issues, including Mr. Montalbano's and Mr. Hriszko's fees. If the Commission does not adopt Staff's normalized level of rate case expense, Staff recommends disallowing these PwC expenses not only from GMO's rate case expense through the true-up, but also any post-true up rate case expenses deferred for future recovery, to the extent any of these expenses are charged to GMO rate case expense.

<u>The Communication Counsel of America and NextSource</u>

The Commission, in its 2010 GMO Rate Case *Report and Order* ordered adjustments to rate case expense concerning NextSource expenses and The Communication Counsel of America (CCA) expenses. Particularly, the Commission found on Page 186 of its *Report and Order* that the services provided could have been performed by in-house attorneys:

> …The CCA provided witness development and coaching services, routine tasks typically performed by retained counsel, internal or otherwise. The KCC also disallowed similar expenses as unjust and unreasonable. The Commission determines that the CCA expense should be disallowed as duplicative of other services that were performed or should have been performed [sic] KCPL's and GMO's attorneys.

Staff has identified an additional $29,148 of rate case expenses KCPL and GMO have paid to The Communication Counsel of America. Staff has made an adjustment to disallow these rate case expenses related to the 2010 Rate Cases.

. The Communication Counsel of America Post-True-Up Expenses	
KCPL-MO	$13,408
MPS	$12,242
L&P	$3,498
Total	$29,148

KCPL and GMO did not defer additional NextSource expenses that were at issue in the 2010 Rate Cases to their post-true-up rate case expenses. KCPL and GMO have removed these expenses from the test year in its Adjustment CS-11, and Staff has reflected these adjustments in its cost of service.

<u>**Rate Case Expense Recommendation**</u>

Staff is maintaining the treatment of 2010 Rate Case expenses incurred prior to December 31, 2010 and the post-true-up 2010 Rate Case expenses pursuant to the Commission's *Report and Order* in those cases. The three year amortization of rate case expense as ordered totals $582,583 for MPS and $367,483 for L&P.

The Commission, in its *Report and Orders*, authorized KCPL and GMO to defer in a regulatory asset their rate case expenses for future recovery subject to review for prudence and reasonableness. While it may have been prudent for KCPL and GMO to retain a seemingly unlimited amount of litigation support during the proceedings of the 2010 Rate Cases, it would be wholly unreasonable to pass on the entire amount of rate case expenses to Missouri ratepayers. Staff's adjustments and totals below detail the amount of 2010 Rate Case expenses Staff is recommending the Commission include in GMO's cost of service and revenue requirements for MPS and L&P for setting rates in this case. In maintaining the defer and amortize approach of rate case expense through the duration of the KCPL Regulatory Plan, Staff recommends a three-year amortization of 2010 post true up rate case expenses, net of Staff's adjustments. As a result of the "defer and amortize" accounting method, Staff recommends GMO's over-collection of 2009 Rate Case expenses reduce the amount of 2010 Rate Case post-true-up rate case expenses to be amortized. At the time of the expected effective date of rates in this case, the over-collection related to GMO's 2009 Rate Case expense will be $198,901 for MPS and $132,750 for L&P. Utilizing this over-collection, the Empire sharing of expenses, and Staff's recommended adjustments, the net deferred costs $260,202 for MPS.

Because there is a relatively small amount of 2010 post-true up rate case expenses charged to L&P, using the over-collection of rate case expense through the effective date of rates in this case results in a negative rate case expense, notwithstanding Staff's adjustments. The table below details these amounts:

Continued on next page.

L&P 2010 Post-True-Up Expenses	
Total Post-True up Deferred Costs	$247,167
Net Reduction for Empire Sharing	($123,831)
Overcollection of 2009 Rate Case Expense through 1/31/2013	($132,750)
Total	($9,414)

Although the calculation above results in a net overcollection, Staff is recommending a normalized level of rate case expense in GMO's costs of service for MPS and L&P going forward, and therefore this amount would not be used to further offset any rate case expenses. Staff recommends the Commission continue the amortization of the Commission Ordered rate case expenses in the GMO 2010 Rate Case Order of $367,483 over three years, or a total of $1,102,448.

The tables below detail the calculation of rate case expenses for MPS and L&P utilizing the overcollection of rate case expenses through January 31, 2013, in recognition of the defer and amortize accounting for these expenses:

Continued on next page.

Summary of Rate Case Expenses reflected in Staff's Cost of Service –MPS		
MPS Only Rate Case Expenses	2010 Rate Case ER-2010-0356, Dec. 31 Cutoff	2010 Rate Case Post True Up expenses
Deferred Costs	3,044,593	
Transfer of Post-True-Up Costs from 2010 Case No. ER-2010-0356	(1,230,865)	1,230,865
Decrease due to over collection of 2007 Rate Case Expenses	(158,966)	
Decrease due to over collection of 2009 Case No. ER-2009-0090 (through January 2013)		(198,901)
Transfer of Post-True-Up Costs from 2009 Case No. ER-2009-0090	188,127	
Reduction of Communication Counsel of America expenses, Commission Order 2010 Case	(16,195)	
Reduction of NextSource Expenses, Commission Order 2010 Case	(78,943)	
Staff Adjustment of Communication Counsel of America Expenses		(12,242)
Staff Adjustment SNR Denton Fees		(5,506)
Staff Adjustment Schiff Hardin Fees		(358,577)
Net Reduction from Empire Sharing of Rate Case Expenses		(395,437)
Total Net Deferred Costs	1,747,751	260,202
Amortization Period	3	3
Annual Amortization Amount	$ 582,584	$86,734

Continued on next page.

Summary of Rate Case Expenses reflected in Staff's Cost of Service –L&P		
L&P Only Rate Case Expenses	2010 Rate Case ER-2010-0356, Dec. 31 Cutoff	2010 Rate Case Post True Up expenses
Deferred Costs	1,165,370	
Transfer of Post-True-Up Costs from 2010 Case No. ER-2010-0356	(247,167	247,167
Decrease due to over collection of 2007 Rate Case Expenses	(36,438)	
Decrease due to over collection of 2009 Case No. ER-2009-0090 (through January 2013)		(132,750)
Transfer of Post-True-Up Costs from 2009 Case No. ER-2009-0090	257,667	
Reduction of Communication Counsel of America expenses, Commission Order 2010 Case	(4,627)	
Reduction of NextSource Expenses, Commission Order 2010 Case	(32,357)	
Staff Adjustment of Communication Counsel of America Expenses		(3,498)
Staff Adjustment SNR Denton Fees		
Staff Adjustment Schiff Hardin Fees		(102,451)
Net Reduction from Empire Sharing of Rate Case Expenses		(123,831)
Total Net Deferred Costs	1,102,448	(115,363)
Amortization Period	3	3
Annual Amortization Amount	$ 367,483	$0

For rate case expenses incurred in the 2012 Rate Cases, Staff is recommending a normalized level utilizing a three year average of rate case expenses using the GMO 2005, 2007, and 2009 Rate Case expenses. Staff does not recommend using the GMO 2010 rate case expenses in an average due to the unique issues in that case, namely Iatan prudence. As can be seen, the 2010 Rate Case expenses were by far the highest during KCPL's Regulatory Plan. Staff recommends a normalized level of $444,849 for MPS and $228,388 for L&P. This amount is an average of GMO's rate case expenses for its 2005, 2007, and 2009 Rate Cases. Staff recommends recovery of this amount over three years, or $148,283 for MPS and $76,129 for L&P per year. This amount would not be subject to true-up for actual expense incurred, or any over or under-recovery recognized.

Staff Adjustments E-149.5 for MPS and E-164.7 for L&P removes the test year amortization of 2009 Rate Case expenses as that amortization ended August 2011.

Staff Adjustments E-149.6 and E-149.7 for MPS and E-164.8 for L&P annualize the test year amortizations of GMO's 2010 Rate Case expenses.

Staff Adjustment E-149.8 for MPS and E-164.9 for L&P add a normalized amount of 2012 Rate Case expenses over a 3 (three) year period.

Staff Expert/Witness: Keith Majors

13. <u>Public Service Commission Assessment Fee / FERC Assessment Fee</u>

The Public Service Commission assessments ("PSC Assessment") are an amount billed to all regulated utilities operating under the jurisdiction of the Commission as an allocation of the Commission's operating costs for regulating those utilities. The PSC Assessment is charged to regulated utilities in Missouri. MPS and L&P's PSC Assessment was annualized using the latest assessment available for the current fiscal year (FY-2012) on information obtained from the Commission's records. The updated rate districts' PSC Assessment was compared to the PSC Assessment amount included in MPS and L&P's test year to form the basis for the adjustment in Staff's cost of service run. Staff also chose to update the Company FERC Assessment paid to represent 12 months ending March 31, 2012. FERC is the Federal Energy Regulatory Commission, and they have a separate assessment to be paid by all regulated utilities, handled in similar fashion to the aforementioned PSC Assessment. L&P Adjustment E-164.6 and FERC Adjustment E-166.2. MPS Adjustment E-147.2 and FERC Adjustment E-148.2.

Staff Expert/Witness: Bret G. Prenger

14. <u>Customer Deposits – Interest Expense</u>

Staff's recommended treatment of customer deposits' interest expense 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 amount GMO paid Missouri customers for interest on their customer deposits, calculated by multiplying the most current customer deposits balance that GMO included in its rate base to 4.25% interest. An amount of interest relating to customer deposits has been included as adjustment to the Income Statement - Schedule 9. Staff calculated the interest for customer deposits consistent with the level of customer deposits reflected in the Rate Base -- Schedule 2 (see discussion in the Rate Base section of this report for customer deposits included in rate base). For this calculation, Staff used the customer deposit balance to be included in rate base, and then multiplied that number by the most current prime interest rate published in the Wall Street Journal (3.25) plus 1%, for a total of 4.25%. The Commission should base its awarded revenue requirement on Staff's recommended amount of interest relating to customer deposits by including the customer deposit interest expense amount calculated by Staff as an expense adjustment to GMO's Income Statement, reflected in Adjustment E-117.1 for MPS and Adjustment E- 125.1 for L&P.

Staff Expert/Witness: Patricia Gaskins

15. Depreciation - Clearing

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 through Adjustment E-157.1 for MPS and Adjustment E-173.1 for L&P.

Staff Expert/Witness: Patricia Gaskins

16. Economic Relief Pilot Program

GMO's Economic Relief Pilot Program ("ERPP" or "program") was approved by the Commission in Case No. ER-2009-0090 as part of a Non-Unanimous Stipulation and Agreement ("Agreement"). The ERPP commenced on September 1, 2009 as a three-year pilot program designed to deliver energy affordability to GMO's qualifying lower-income residential customers through the application of a "fixed credit," thus allowing those participants to make full and timely payments on their monthly bills. The program is scheduled to end September 1, 2012. As set out in the Agreement, the ERPP provides up to 1,000 participants a monthly "fixed credit" not to exceed $50 per month, as long as the participant continues to meet the ERPP eligibility requirements and reapplies to the program annually. The ERPP tariff sheet that took effect September 1, 2009 states that annual ratepayer funding for the ERPP is matched dollar for dollar by GMO.

Issue

GMO is recommending the expansion of the existing program, from 1,000 participants to 2,500 participants, based on an expectation of a positive evaluation of the program. In addition, GMO is also recommending that the program funding be changed from 50% ratepayer funded and 50% GMO contribution to 100% ratepayer funded. Staff's initial concern with GMO's recommendation is that it is based on the unknown.

Analysis

Staff believes a comprehensive, independent evaluation of the ERPP is required before considering sustainability, expansion or modification, and alternative funding of the program. Direct testimony provided by GMO's witness Jim Alberts indicates GMO acquired a third party evaluator, True North Market Insights, LLC, to evaluate the program. GMO obtained the third party evaluator as recommended by Staff witness Gay Fred in Staff's Cost of Service Report in Case No. ER-2010-0356. The purpose of the third party evaluation is to address all aspects of the program for weaknesses, strengths and improvement opportunities. Mr. Alberts' direct testimony states that GMO will provide complete evaluation results by the end of 2nd quarter 2012 in a report by GMO. Additionally, Mr. Alberts advises that Staff, and the other parties in the advisory group, will receive the complete evaluation. However, to date, Staff has not received any report containing an evaluation of the ERPP, which Staff believes is critical before considering program sustainability, expansion or modification, and alternative funding source.

Recommendation

Staff recommends the ERPP remain a pilot program, maintaining currently authorized participation levels, current program terms, and that program funding of 50% ratepayer funded and 50% GMO contribution remain unchanged at this time.

Accounting Treatment

Staff's recommended treatment of the ERPP is to include the costs MPS and L&P have incurred during the period of December 31, 2010 through March 31, 2012 (as explained below) and an ongoing level of expense based on the parameters established in the Stipulation and Agreement in Case No ER-2009-0090. According to the Stipulation and Agreement,

> The Signatories agree that GMO can defer 50% of the costs of its Economic Relief Pilot Program in a regulatory asset until the next rate case, with cost recovery to be determined at that time. The remaining 50% of such cost will be borne by GMO's shareholders.

Staff made an adjustment to reflect a three year amortization of deferred ERPP costs for the period December 31, 2010 through March 31, 2012 which is reflected in Staff's Accounting Schedule 9, adjustment E-123.6 for MPS and adjustment E-131.4 for L&P. In addition, Staff included an ongoing level of expenses represented by the costs GMO incurred related to the

ERPP during the 12-month period ended September 30, 2011; however, Staff's inclusion of this amount is specifically predicated upon GMO continuing to incur ERPP costs in the future at twice the level Staff has included in GMO's revenue requirement, i.e., that GMO's shareholders continue to fund at least the same level of ERPP costs that Staff has included in GMO's revenue requirement.

Staff Experts/Witnesses: Contessa Poole-King and Karen Lyons

17. Low-Income Weatherization Program

The funding for the GMO 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 last rate case, Case No. ER-2010-0356[85]. Since then, GMO, in its Missouri Energy Efficiency Incentive Act (MEEIA) filing, Case No. EO-2012-0009, has requested that the Commission approve the low-income weatherization program as a MEEIA program. Case No. EO-2012-0009 is pending approval by the Commission. If the MEEIA filing is not concluded by the true-up filing date of November 2, 2012, in this case, Staff recommends the Commission Order:

1) GMO low-income weatherization funds collected from customers but not utilized by the Weatherization Agencies in the previous years of 2010 ** _______ **, 2011 ** _______ **, 2012, be made available to the Weatherization Agencies in GMO's service territory for future use;
2) GMO continue to collect $150,000 for low-income weatherization in rates annually if there is no resolution to the MEEIA case by the November 2, 2010, the date true-up direct testimony is due;
3) GMO consult the KCP&L DSM Advisory Group (DSMAG) on the allocation and distribution of low-income weatherization funds; and

[85] *In the Matter of the Application of Kansas City Power & Light Company for Approval to Make Certain Changes in its Charges for Electric Service to Continue the Implementation of its 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).

NP

4) That GMO provide quarterly reports to the DSMAG on the allocation and distribution of funds to the GMO Weatherization Agencies.

5) That GMO file tariff sheets that revise Tariff Sheet Nos. R-62.03, R-62.04, R-62.04.1 and R-62.04.2 to comply with the Order in from this case if there is no resolution to the MEEIA case by the November 2, 2010, the date true-up direct testimony is due.

There are specific programs designed to help low-income customers with energy conservation. 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 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 Natural Resources (MDNR). 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 GMO's service area. For the GMO Weatherization Program, GMO administers funds at the local level for weatherization of its qualified low-income customers which is performed by the Kansas City Housing and Community Development Department (KCHCDD), 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). Until recently CSI provided low income weatherization in the CAPSTJO counties, so no funds were directly allocated to CAPSTJO. These Weatherization Agencies, the authorized funding and funding provided are listed in Appendix 3, Schedule HEW-1. In addition, the areas served by all the MDNR Weatherization Agencies in Missouri, with those eligible for funds from GMO annotated, are shown in Appendix 3, Schedule HEW-2.

The federal government, through the American Recovery and Reinvestment Act (ARRA) provided special funding of $128 million for the Missouri Weatherization Program for the period of April 2009 – March 2012 ("ARRA Period"). The ARRA provided an average of $6,500 of weatherization for households with income at 200% or less of the Federal Policy Guidelines. In the three year period prior to the ARRA (2006-2008) federal funding for the Missouri Weatherization Program was approximately $18 million and the average amount per household was $3,000. The amount of weatherization funding increased from about $3,000 to an average of $6,500 per household. Some Weatherization Agencies have already utilized all of the ARRA funding allocated to them while others are making a concerted effort to utilize the ARRA funding before the December 2012 deadline for utilizing the funds.

In addition to the amount of money provided through ARRA, in GMO's last rate case, GMO was authorized to continue to contribute $150,000 annually to the Weatherization Agencies for the weatherization of qualifying customers' homes, and to recover this amount in rates. No specific allocation of funds to the Weatherization Agencies was in the Order. According to *Low Income Weatherization Program Status Reports*, submitted to the Commission April 13, 2012, as shown on the attached spreadsheet, *Low-Income Weatherization Program*, (Schedule HEW-1), GMO provided ** _____ ** to the five weatherization agencies in its service area in 2011. This is ** __ **[86] of the funds collected in rates for weatherization. This under-utilization of funds is likely due to the Weatherization Agencies' focus on using the ARRA funding and restrictions on ARRA funds being combined with utility funds.

KCPL provided Staff *Survey Results* from an informal survey of the weatherization agencies they utilize in the KCPL and GMO weatherization programs at the DSM Advisory Group meeting January 19, 2012. The weatherization agencies responses were generally favorable but the weatherization agencies were not asked if they could use more funding, although one agency commented that it could use more funding[87].

It is Staff's position that the GMO annual low-income weatherization funding of $150,000 for the GMO Weatherization Agencies, should be continued. However, as a condition to GMO continuing to collect this amount in rates, Staff also recommends that the Commission order that GMO provide the unused funds from 2010, 2011, and 2012 be made available solely

[86] *KCP&L Low Income Weatherization Program Status Reports*, submitted to the PSC, April 13, 2012
[87] *Survey Question*, KCP&L, document provided at KCP&L DSM Advisory Group meeting, January 19, 2012.

NP

for the GMO Weatherization Agencies for low-income weatherization funding. If there is no resolution to the MEEIA case by the November 2, 2010, the date true-up direct testimony is due and $150,000 per year funding is included in rates, Staff recommends a change from the current monthly reimbursement funding. In order to increase the utilization of the funds for low income weatherization, Staff recommends the Commission order GMO to provide half of the annual funding to the Weatherization Agencies at the start of the program year and then dispense additional funds to the Weatherization Agencies as the initial funds are utilized.

Staff recommends that the Commission order GMO to provide monthly reports to the DSMAG on low income weatherization funding and expenditures and submit the reports as non-case related submissions in EFIS. The DSMAG should work with GMO to review the allocation and utilization of funds by the Weatherization Agencies to determine if any adjustments are needed. This review in the way funds are disbursed and utilized will have the goal of a higher utilization of funds by the GMO Weatherization Agencies.

Subsequent to Case No. ER-2010-0356, GMO did not file tariff sheets to revise sheet numbers R-62.03-R-62.04.2 to comply with the Commission's Order regarding the Low Income Weatherization Program. Therefore, if there is no resolution to the MEEIA case by the November 2, 2010, the date true-up direct testimony is due; Staff recommends that the Commission order GMO to file tariff sheets that revise Tariff Sheet Nos. R-62.03, R-62.04, R-62.04.1, and R-62.04.2 to comply with the Commission's order in this case.

Staff Expert/Witness: Henry Warren

18. <u>SPP Administrative (Schedule 1-A) Fees</u>

As noted in GMO's direct testimony, the Southwest Power Pool, Inc. (SPP) is a not-for-profit, regional transmission organization (RTO) entity which maintains functional control over the transmission assets of its members and provides transmission services through its Federal Energy Regulatory Commission (FERC)-approved open access transmission tariff (OATT). SPP's costs must be recovered from its users (transmission customers). Consequently, as a member of SPP, GMO pays SPP an administration charge for performing transmission functions on its behalf. Staff adjustments annualize SPP administration charges to Accounts 561 and 575 through March 31, 2012.

Under its OATT, the SPP establishes a rate for its administration charge annually that enables it to recover 100% of its total annual costs for RTO functions, subject to a rate cap. SPP's administration charge is set each year based on projected costs and revenues for that year. 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.

On October 25, 2011, the SPP Board of Directors approved the SPP Finance Committee's recommendation that the Board of Directors establish an assessment rate and tariff administrative fee (schedule 1-A) of $.255 per MWh beginning January 1, 2012. According to SPP meeting minutes, the SPP's cash forecast indicated that a rate of $.255 per MWh was sufficient to fully fund SPP's operations during the 2012 year with projected increases to $.280 per MWh in 2013 and $.30 per MWh in 2014. The Staff's annualized amount of SPP Administrative fees in this case was based on the January 2012 rate of $.255 per MWh.

The SPP's 2012 administrative fee of $.255 per MWh is based on a SPP net revenue requirement (NRR) of $89,560,000, which is an approximately 14 percent increase from its 2011 budgeted NRR of $78,638,000. According to SPP documents, the primary driver of this increase is expected additional salaries and benefits for the Integrated Marketplace development. The 2012 budgeted NRR of $89,560,000 divided by SPP's projected billing determinants of 353,453,000 MWh, results in a calculated administrative cost of $.253 per MWh, but SPP management recommended an administrative fee based on a NRR of $90,130,515, or $570,000 over-budgeted cost requirements.

The Staff's March 2012 annualized SPP administration fees included in its revenue requirement proposal for MPS total $2,562,127, compared to test year costs of $2,273,743 for an increase of $288,384. The Staff's March 2012 annualized SPP administration fees included in its revenue requirement proposal for L&P total $1,004,691 compared to test year costs of $820,852 for a increase of $183,839.

Staff Expert/Witness: Charles R. Hyneman

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

MPS and L&P charge transmission expense to Account 565 Transmission of Electricity by Others. The Staff's twelve months ended March 2012 annualized transmission expenses for

GMO have decreased for both MPS and L&P. The Staff's March 2012 annualized transmission expense included in its revenue requirement proposal for MPS is $8,351,448, compared to test year costs of $9,206,151, for a decrease of $854,703. The Staff's March 2012 annualized transmission expense included in its revenue requirement proposal for L&P is $1,558,610 compared to test year costs of $2,478,874 for a decrease of $920,264.

Staff Expert/Witness: Charles R. Hyneman

X. Depreciation

A. Recommendations

1. Staff recommends the Commission order GMO to continue to use the depreciation rates ordered in the prior rate case Case No. ER-2010-0356 and the new account depreciation rates ordered in Depreciation Authority Order Case No. EO-2012-0340, with the exception of the method of computation of monthly depreciation accruals for select general plant accounts using the experimental vintage amortized method.

2. Staff recommends that the experimental switch of select general plant accounts to a vintage amortization method allowed in prior rate case Case No. ER-2010-0356 not be allowed to be put in place on a permanent basis, and these accounts revert back to a depreciation accrual method, including booking plant retirements as they actually occurred during the vintage amortization trial period.

3. Staff recommends the Commission order GMO to make an adjustments in general plant reserves accounts of a total of $28,575,233 to address an under-recovery of plant, (deficiency in depreciation reserves). Staff is recommending four adjustments:

    - An adjustment, (increase of reserves), of $20,676,360 related to early retirements of plant and equipment related to former Aquila facilities consolidations and relocations with KCPL and Great Plains attributable to the acquisition by Great Plains.

    - An adjustment , (increase of reserves), of $4,221,178 to correct the Company books to reflect the premature stopping of depreciation initially reported in Case No. ER-2009-0090. Response to Staff DR 0247.

    - And a transfer of $3,675,695 from transmission plant reserves (that are collectively over accumulated in excess of $13,000,000) to distribute within general plant accounts 390, 391, 393, 394, 395, 397, and 398.

- Staff recommends the Commission order GMO to transfer the $18,820,501 in account 119.300 to account 108 and distribute $18,820,501 into the appropriate equivalent defined GMO ECORP reserve accounts such that the individual general plant reserves accounts reflect the appropriate Missouri depreciation reserves on the Company books.

4. Staff recommends the transfer of accumulated reserves between accounts within the general plant accounts, such that in conjunction with the $28,575,233 from recommendation 3 above, result in a rebalancing of reserves in the general plant accounts to remove over and under-recovery in accounts 390, 391, 393, 394, 395, 397, and 398. A table below shows the amounts associated with each account to transfer, Table: **Adjustment Amounts For General Plant**.

5. Staff recommends the Commission order GMO to conduct a physical inventory of plant in service in the general plant accounts for all non production facility locations, submitting the results of this physical inventory with the next depreciation study due the earlier of June 30, 2015 or June 30, 2013 with a rate case, including a record of all plant transaction activity conducted as a result of this physical inventory.

6. Staff recommends the Commission direct GMO to complete by June 30, 2013 the studies described in Paragraph 10 of the *Nonunanimous Stipulation and Agreement Regarding Depreciation and Accumulated Additional Amortizations* the Commission approved and ordered in Case No. ER-2010-0355 and ER-2010-0356, ("Depreciation Stipulation") and provide the results by the end of July 2011 as described in the Depreciation Stipulation. Staff requests the Commission direct Staff as to whether it should file a complaint against GMO for its failure to provide study results as described in the Depreciation Stipulation.

B. Introduction

In Case No. ER-2010-0356, GMO requested authority to record a special amortization to address an alleged under-recovery of plant for the general plant accounts. Also in that case, GMO requested a change in the authorized method of computation of monthly depreciation accruals for select general plant accounts. Pursuant to the Depreciation Stipulation in Case No. ER-2010-0355 and ER-2010-0356 "If KCPL or GMO seek to continue use of the Amortization Method as specified in this Agreement in the next rate case, they must submit testimony in that rate case showing why the Amortization Method should be continued." GMO has not presented testimony showing why the Commission should authorize use of the amortization method. Not only has GMO not justified use of the amortization method, but also, as discussed below, use of the amortization method is particularly problematic for GMO given certain record-keeping deficiencies.

The Depreciation Stipulation also required KCPL and GMO to perform a study regarding retirements of general plant retired as a consequence of office moves and corporate mergers. GMO has not submitted study results as required by the Depreciation Stipulation. In the absence of a GMO study, Staff undertook an independent study and recommends a number of account transfers based on Staff's independent study results. The results of that study are attached as Appendix 3, Schedule AWR-1.

Finally, as discussed below, the evidence of poor plant records brings into question not only the accuracy of the plant in service record, but the retirement record used in depreciation studies. At various meetings with KCPL personnel knowledgeable in GMO plant records and GMO history, Staff has asked if and when physical inventories were conducted on plant in service for general plant accounts. Company personnel could not recall having conducted physical inventories. Staff's recommendation is that the Commission order GMO to conduct a physical inventory of all plant recorded in service at non production facilities for the general plant accounts, and submit the results of this physical inventory with the next depreciation study, including a record of all plant transaction activity conducted as a result of this physical inventory.

C. **Amortization Method:**[88]

The Depreciation Stipulation provided that:

> The Signatories request that the Commission authorize KCPL and GMO to utilize the "Amortization Method" for specified General Plant accounts. The Amortization Method is a straight line method, in that the depreciation starts when the equipment is installed and stops when the equipment value is fully depreciated. For regulatory mass property accounting purposes, all of the additions to an account over a vintage (one year or one month of additions) are depreciated over a set amortization period. For depreciation accounting purposes, all of the equipment in each vintage is retired at the end of the amortization period. No interim retirements are recorded….

Staff recommends that the Commission order GMO to record monthly depreciation accruals based on actual plant in service, using a depreciation rate computed from an average service life equivalent to the trial amortization period for accounts 391, 393, 394, 395, 397,

[88] In this context, the term "amortization method," refers to the same practice as the term "vintage amortization." Although the Depreciation Stipulation in Case No. ER-2010-0355 used the term "amortization method," the term "vintage amortization" is more precise, and Staff will use that term in this Report.

and 398. Staff included adjustments to plant and reserves in the vintage amortized accounts as a substitute for actual retirements that occurred during this trial period, but were not recorded to the Company books.

The vintage amortization method is a simple amortization of investment starting in the year the plant is placed in service. Use of vintage amortization also forces the over or under accumulated reserve in each account to be addressed by either a transfer to other accounts or as a separate amortization. Thus use of the amortization method provides a less precise reflection in rates of the current plant in service, and the act of changing to the amortization method form normal regulatory depreciation typically requires additional rate-making treatment. In order for Staff to have the opportunity to conduct effective regulatory oversight of cost of service, the plant records and retirement rates for actual plant in these accounts must be available for review and study.

D. **Reserve Transfers and Adjustments of Reserves**

Under-recovery of depreciation reserves may occur due to: 1) the Company failing to properly record depreciation of plant still in service, 2) the depreciation analysis or record of retirement history used for projections was in some way defective, or 3) unexpected events occur resulting in retirements earlier than forecast. Staff undertook a study to analyze the dollars of GMO's alleged under-recovery attributable to each of these causes. The results of that study are attached as Appendix 3, Schedule AWR-1.

Staff found the GMO general plant reserve as currently booked to be under recovered by approximately $28,575,233. This includes accounts currently using the trial basis vintage amortized method of accrual, plus account 390 (Structures).

Failure to book appropriate Missouri depreciation

Staff has identified two issues concerned with GMO's depreciation accruals that occurred prior to its acquisition by Great Plains. The first is the premature halting of depreciation accruals, and the second is 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 a data request in that case as $3,942,866, and was updated in

Rosella Shad's Surrebuttal Testimony and the Staff's Cost-of-Service Report as $4,221,178. This issue was not addressed in any stipulation or Commission order since it has been identified, nor has GMO recorded any adjustments to correct this issue. GMO should book a $4,221,178 addition to reserves as a reduction to the Company's earnings.

Booking of depreciation accruals at "Corporate" depreciation rates (not Missouri approved rates) was a normal practice under the management of GMO when it was named Utilicorp United and Aquila. This resulted in the booked accumulated reserves for most general plant accounts to exceed the correct amounts for Missouri regulated plant. The difference between Company book and appropriate Missouri reserves was tracked and accumulated in FERC USOA account 119.300. FERC USOA account 119.300 is defined as "Accumulated provision for depreciation and amortization of other utility plant"

This Company booking of depreciation accruals for general plant that did not represent the correct Missouri jurisdiction amounts was halted when Aquila was acquired by Great Plains. After the acquisition GMO has booked depreciation accruals per the ordered Missouri depreciation rates. These amounts in account 119.300 totaling $18,820,502 continue to be kept in account 119.300 by the Company, and are used to adjust book reserves to Missouri reserves for GMO (ECORP, MPS and L&P) for Missouri rate cases. Staff lists separately these 119.300 reserve adjustment amounts in the Staff accounting schedules as "UCU Common General Plant" for all GMO rates cases through ER-2010-0356.

In Case No. ER-2010-0356, these amounts were defined as unrecovered plant and mistakenly defined as the origin of the under-recovery of reserves in the general plant accounts. This confusion contributed greatly to difficulties in the parties agreeing on the definitions and methods to study the under-recovery of reserves as required by the Depreciation Stipulation. A study by GMO has not occurred. The Depreciation Stipulation referenced reserve transfers between the Transmission plant accounts and the General plant accounts has not occured. The fact that the appropriate Missouri accumulated depreciation reserves are attained by adjusting current company book reserves by amounts recorded elsewhere (account 119.300 containing a negative $18,820,501) is not a cause of any under or over recovery of plant. Staff recommends the Commission order GMO to transfer the amounts in account 119.300 into account 108 and distribute $18,820,501 into the appropriate equivalent defined GMO ECORP reserve accounts such that the individual accounts show the appropriate Missouir depreciation reserves on the Company books.

E. Transferred to Non Utility Property Then Sold Facilities

For general plant structures account 390, Staff's investigation of facility sales transactions with respect to GMO general plant accumulated depreciation reserves is summarized as follows: GMO transferred three facilities to non utility property and then sold them, specifically the 20 West 9th former Aquila headquarters, the Platte City Service Center and the Liberty Service Center. The transfer of an original cost of $56,095,584 for these three facilities with an accumulated depreciation of $10,985,769 resulted in a reduction in regulated rate base of $46,722,668. The facilities were eventually sold for a total sales proceeds of only $12,882,362. On the non regulated books, the Company booked a $31,520,177 write-down of assets to Goodwill for the former Aquila headquarters facility. If a normal retirement of these facilities had been booked in the regulated utility accounts, the total original cost would have been removed from plant and reserves, with the sales proceeds recorded into reserves as salvage resulting in a reduction of rate base by only the $12,882,362 sales proceeds, and creating a $33,840,306 deficit in the reserves. Staff's subsequent analysis, described below, of depreciation accruals in structures account 390 for GMO-ECORP, MPS and L&P found an under-recovery of reserves of only $870.

For general plant accounts other than account 390, specifically the accounts for computer hardware, computer software, and communications equipment, GMO retired plant on the regulatory books that become no longer used or useful as a result of facility consolidations and relocations attributable to consolidation of certain of its operations with KCPL. Staff's investigation of general plant for accounts other than account 390 estimated a shortfall in reserves attributable to facility consolidations and relocations of $20,272,790 for GMO-ECORP, MPS and L&P.

Accuracy of Company Booked Plant In Service. Staff investigated the historical retirement record itself. For general plant accounts at service facilities, multiple instances of plant and equipment recorded as still in service were identified and confirmed to not be in service. Staff also reviewed additions and retirements to the structures account 390 related to building modifications and additions. KCPL personnel knowledgeable in GMO plant records stated that near the end of a facility modification project, the property records person(s) and the project management person(s) do a physical walk through and try to identify the items that are now missing or removed from service. Staff contends that this method of identification of retirements has a high probability of introducing errors over multiple years of layered projects if periodic physical inventories are not conducted. Staff's review of company-provided detailed list of plant and equipment in service allowed Staff to easily identify items which Staff doubted would still exist or be in service simply due to the type of item and the vintage. GMO admitted that the majority of the questionable items were probably not used or useful or still physically present. These discrepancies indicate that GMO has an audit problem that can only be corrected by the Company conducting a physical inventory. Staff reviewed plant in service records for the general plant accounts at all company locations. The facilities that Staff easily identified questionable booked plant in service were service facilities. For the production facilities, Staff found no questionable booked items by simply looking at plant records. Thus, Staff's recommendation to conduct a physical inventory of general plant is limited to non production facilities.

The evidence of poor plant records brings into question not only the accuracy of the plant in service record, but the retirement record used in depreciation studies. At various meetings with KCPL personnel knowledgeable in GMO plant records and the Company history, Staff has asked if and when physical inventories were conducted on plant in service for general plant accounts. Company personnel could not recall having conducted physical inventories.

F. Transfer of Reserves from the Transmission accounts to General Plant Accounts

The Depreciation Stipulation suggests the transfer dollars from the over-accumulated depreciation reserves in the transmission accounts to the general plant accounts is an appropriate action to address the shortfall, which Staff estimates to be an approximate total of $28,575,233, in general plant accounts. However, Staff's study indicated that a major portion, $20,676,360, of this shortfall in the depreciation in the general plant accounts is a result of the Aquila acquisition by Great Plains; therefore, this portion of the shortfall should be treated as an acquisition detriment. Staff's recommends an adjustment (increase) of reserves in the general plant accounts by $20,676,360.

G. Assignment of the contributing sources (causes) of the under-recovered amounts

Abnormal and unexpected events are included in GMO's retirement history. The acquision by Great Plains of Aquila resulted in abnormal and unexpected retirements as a result of office and service center consolidations and relocations. Staff concluded that an under-recovery, (deficiency in depreciation reserves), in the general plant accounts for GMO of $20,676,360 is associated with its acquision by Great Plains and the resultant closure and consolidation of facilities with Great Plains and KCPL facilities. Staff recommends an adjustment (increase) of reserves in the general plant accounts by $20,676,360

In the table below, the amounts of $807 for account 390 and $20,675,553 for amortized accounts only, totaling $20,676,360 represents Staff's estimate of the amount of accumulated reserve under-recovery contributed from early retirements as a result of consolidations and relocations attributable to the acquisition by Great Plains. The years 2007 through 2011 include retirements recorded for plant and equipment that was still functionally usable, but no longer used or useful within the new organizational structure. These retirements resulted in a steep increase in retirement rate for general plant accounts. The result is a steep decrease in accumulated depreciation reserves as the original cost of each retirement is deducted from reserves. For retirements earlier than expected the accumulated accrued depreciation for the item is less than the original cost, resulting in a reserve deficit, or under-recovery of plant.

Continued on next page.

A positive number is an under-recovery in this table.

	GMO $ Total	ECORP $	MPS $	L&P $
Acct 390 only (2008)				
Stopped Depreciation	0	0	0	0
Depreciation Mismatch	6,109,870	3,226,639	1,826,733	1,056,498
Acquisition by Great Plains	807	(319,533)	250,957	69,383
Acct 390 Under-recovery	6,110,677	2,907,106	2,077,690	1,125,881
Amortized Accts Only (2011)				
Stopped Depreciation	4,221,178	0	3,175,592	1,045,586
Depreciation Mismatch	(2,434,175)	1,524,753	(2,194,341)	(1,764,587)
Acquisition by Great Plains	20,675,553	18,748,037	1,417,963	509,553
Amortized Accts Under Recov	22,462,556	20,272,790	2,399,214	(209,448)
Total Amortized + Acct 390				
Stopped Depreciation	4,221,178	0	3,175,592	1,045,586
Depreciation Mismatch	3,675,695	4,751,392	(367,608)	(708,089)
Acquisition by Great Plains	20,676,360	18,428,504	1,668,920	578,936
General Plant Under-recovery	28,573,233	23,179,896	4,476,904	916,433

Table: Adjustment Amounts For General Plant

GMO Summary Table Unrecovered General Plant Reserves

Positive Number = reserve deficit

Account Acct #	Juris Unrec 2011 ECORP	Juris Unrec 2011 MPS	Juris Unrec 2011 L&P	GMO Total
391	1,861,687	159,399	344,032	2,365,118
391.02	5,070,047	863,726	294,233	6,228,006
391.04	10,465,873	86,640	1,277,254	11,829,767
393	(5,648)	(572)	(153,824)	(160,043)
394	14,885	(850,559)	(46,343)	(882,018)
395	13,543	(296,506)	(82,584)	(365,548)
397	2,805,308	(359,748)	775,773	3,221,333
398	47,095	188,173	(9,327)	225,941
Amortized Tot	20,272,790	(209,448)	2,399,214	22,462,556
Acct. 390	2,907,106	2,077,690	1,125,881	6,110,677
Total	23,179,896	1,868,242	3,525,095	28,573,233

The $28,573,233 shortfall is made up by reinstatement to reserves from GMO of $4,221,178 for stopped depreciation and $20,676,360 for early retirements attributable to the acquisition by Great Plains, and a transfer of $3,675,695 from transmission accounts 353 (Station Equipment) and 354 (Towers and Fixtures) reserves. The MPS and L&P allocated transmission accounts show an over accumulation of reserves in excess of $13,000,000 in the depreciation study conducted by Staff in the prior rate case, Case No ER-2010-0355.

Derivation of Dollar Amounts
Amortized Accounts

The Amortized Accounts Under-recovery line shows $22,462,556. This is the difference at Dec. 31, 2011 for all GMO vintage amortized accounts between the sum of all of the vintage amortizations and the reserves booked in these accounts. The sum of each vintages amortization for this type of depreciation expense accrual may be conducted at any time and compared to booked amounts without conducting a depreciation study. Any deviation in the two, such as from cost of removal or salvage, may be addressed in any rate case. The amount in this rate case, $22,462,556, to address represents a "stranded" amount carried over from the prior depreciation accrual method, and reflects an under accrual of depreciation. The vintage amortization method will not cover or compensate for booked accumulated depreciation reserves which do not match expected accrued amortization. It is labeled "stranded" because there is no automatic method, such as the use of remaining life depreciation rates, to address these amounts. The above table, **Adjustment Amounts For General Plant**, shows the amounts for each account.

Account 390, Structures and Improvements

Account 390 Under-recovery, $6,110,677, in the above table represents an under-recovery in this account. This amount was estimate using the depreciation study results presented by GMO in the prior rate case, Case No. ER-2010-0356. It is the difference between calculated theoretical reserves and book reserves as of Dec. 31 2008.

Stopped Depreciation

For GMO, Staff's investigation of general plant accounts to satisfy the Case No. ER-2010-0356 Depreciation Stipulation study of causes of under-recovery of plant, includes recognition of prior rate case discovery of failure under Aquila to properly book depreciation accruals for plant still in service. GMO has failed to adjust the reserves voluntarily to account for this $4,221,178 originally identified by GMO's response to Staff Data Request No. 0247 in Case No. NO. ER-2009-0090.

Depreciation Mismatch

Depreciation mismatch is used as a name to indicate under or over-recovery of plant attributed to normally expected drift over time between forecast (ordered depreciation rate) and actual retirement rate. The table amounts shown were derived by difference, that is, whatever still exists after other causes are accounted for. In the above table, this is the $ 6,109,870 for account 390 and $(2,434,175) for amortized accounts, totaling $3,675,695. The actual retirement history has essentially been lost. Only an indirect estimate method is available.

Acquisition by Great Plains

The portion of the under-recovery assigned as Acquisition by Great Plains, $20,676,360, in the above table is the Missouri jurisdictional amount Staff derived from the analysis of elevated retirement rates versus normal expected retirement rates for the 5- year period of 2007 through 2011 capturing the acquision by Great Plains, and attributed to closures, relocations and consolidations of offices and service centers with KCPL.

Accounts Not Included in the Study

Of all the general plant accounts, Staff did not include transportation equipment (account 392), or power operated equipment (account 396) within this stipulation related study. The reasons are: Depreciation studies for the last case found overall accumulated reserves for these accounts at reasonable levels for the age of the equipment at that time. These accounts were not switched to the general plant amortization method. Typical equipment in these accounts are large items with maintenance records and vehicle registration requirements, etc., which, although they migrate around the Company, are not easily overlooked when retirements should be booked.

H. Regulatory Depreciation

Staff does not recommend any change in currently ordered depreciation rates, other than to return the general plant accounts subject to the Amortization Method trial period be returned to a traditional depreciation accrual method. The depreciation rates remain unchanged from those in effect prior to Case No. ER-2010-0356, and are the same depreciation rates ordered in that rate case, only the computation method of the monthly accrual changes.

Staff Expert/Witness: Arthur W. Rice

XI. Current and Deferred Income Tax

A. Income Tax Expense

The Staff has not taken any issue with the dollar amounts, calculations and methodology used by GMO in the calculation of current and deferred income tax expense in this direct case. Given the significant amount of bonus depreciation and other deductions currently being allowed by the IRS, there is a potential for Staff's income tax expense recommendation to change significantly in its August 31, 2012 true up audit revenue requirement recommendation. Staff recognizes that due to the increased bonus depreciation and other liberalized allowed tax deductions, GMO may not be able to recognize the full amount of all tax deductions and tax credits that it otherwise would be able to take advantage of on a true utility stand-alone basis. At this point in time Staff is unable to predict the dollar amount of any true-up changes to the level of income tax expense that it is including in its determination of GMO's revenue requirement in this direct filing.

The Staff is recommending in KCPL's companion rate case that the Commission order KCPL to allocate to GMO its appropriate ownership share of the Iatan 2 Advanced Coal Tax Credit. If this tax credit is not reflected as a reduction to GMO's income tax expense in this case, GMO's customers will be unfairly penalized by the actions of KCPL. Staff witness Cary G. Featherstone is addressing this issue in this Cost of Service Report.

Staff Expert/Witness: Charles R. Hyneman

B. Accumulated Deferred Income Taxes

GMO's deferred tax reserve represents, in effect, a prepayment of income taxes by GMO's customers to GMO before GMO pays the federal and state taxing authorities. As an example, because GMO is allowed to deduct depreciation expense on an accelerated basis for income tax purposes, the income tax depreciation expense deduction GMO uses for paying income taxes is currently considerably higher than depreciation expense used for ratemaking purposes. This results in what is referred to as a "book-tax timing difference," and creates a deferral of income taxes to the future.

GMO's deferred tax reserve includes deferred tax assets (debit balances) and deferred tax liabilities (credit balances). The net credit balance in GMO's deferred tax reserve represents a source of cost-free funds for GMO to use for its utility operations. Therefore, Staff has reduced MPS and L&P's rate base by this deferred tax reserve balance to avoid having customers pay a return on funds that are cost-free to the Company.

Both GMO and Staff are in agreement that the deferred tax impact of the individual events and transactions that are included in and/or related to GMO's cost of service in the provision of electric utility service should be included in GMO's accumulated deferred tax reserve and included in its rate base.

Based on the Staff's review of the individual components of MPS and L&P's deferred tax reserve the Staff does not agree with one of GMO's classifications. GMO's fuel adjustment clause is related to GMO's cost of service, and absent evidence to the contrary as to why it should not be included, it should be included in the net amount of deferred taxes reflected in rate base.

As part of its true-up audit, the Staff will re-examine accumulated deferred income tax balances to make sure all items included in those balances are consistent with the other components of GMO's cost of service and revenue requirement, and that they reflect the current balances at the true-up cutoff date of August 31, 2012.

Staff Expert/Witness: Charles R. Hyneman

XII. Qualifying Advanced Coal Project Credit for Iatan Unit 2 Facility

Summary and Conclusions

Great Plains Energy, KCPL, and GMO and Aquila, Inc. (Aquila) prior to the acquisition of Aquila (now GMO) by Great Plains Energy– engaged in improper conduct and imprudent decision-making with regard to the Qualifying Advanced Coal Project Credit for the Iatan 2 Generating Unit ("Iatan 2").

Because of this improper conduct and imprudent decision-making, Staff recommends the Commission order Great Plains Energy, KCPL and GMO to request a reallocation between KCPL and GMO of the Iatan 2 Qualifying Advanced Coal Project Credits from the Internal Revenue Service ("IRS"), at Great Plains shareholder expense. If the IRS does not reallocate these Iatan 2 coal credits to GMO based on its ownership share of the power plant, then KCPL should pay the monetary equivalent to GMO of the value of the coal credits that should be allocated to GMO.

In the alternative, the Commission could disallow a portion of the Great Plains Energy, KCPL and GMO officers' salaries and benefits allocated to GMO. Or, as another alternative, Staff recommends the Commission consider the imprudence of Great Plains Energy, KCPL and GMO regarding the qualifying advanced coal project credit when it determines what return on equity would be reasonable for both KCPL and GMO in these rate cases.

Introduction/Recommendations

Staff recommends that the Commission order the reallocation of the Iatan 2 Qualifying Advanced Coal Project Credit between KCPL and GMO based on the respective ownership share of each company. Staff further recommends the Commission order Great Plains Energy (as the parent of both KCPL and GMO), KCPL, and GMO to initiate a formal application process with the IRS for the reallocation of Coal Credits to include GMO's 18% ownership share. Because Iatan 2 is allocated between MPS and L&P, it is also necessary to allocate an amount for the advanced coal credits to each. Staff recommends the Commission allocate GMO's share of the advanced coal credits to the revenue requirements of MPS and L&P based on the same percentage used to assign and allocate GMO's Iatan 2 costs between MPS and L&P. Further, Staff recommends the Commission order Staff to actively participate in the reallocation application process of Great Plains Energy, KCPL and GMO with the IRS to monitor the request to reallocate the advanced coal credits to ensure GMO is properly represented during the process.

If the IRS does not allocate a share of the Qualifying Advanced Coal Project Credit to GMO, Staff recommends the Commission order KCPL to provide monetary equivalents to GMO up to the level of GMO's rightful share of coal credits.

In the alternative, Staff recommends the Commission disallow the allocation of Great Plains Energy, KCPL, and GMO officers' salaries and benefits to MPS and L&P in determining their revenue requirements because the Great Plains Energy entities – and Aquila prior to the acquisition of Aquila (now GMO) by Great Plains Energy – acted imprudently on at least six separate occasions in the decisions to not allow GMO to apply for the qualifying advanced coal project Credit or to participate in the Arbitration process or the re-allocation process, and ultimately decided to affirmatively waive GMO's right to request an allocation of the coal credits from the IRS when The Empire District Electric Company ("Empire") requested and received permission to receive a share of these credits. The instances when Great Plains entities and

Aquila had the opportunity to seek to provide GMO its claim to its rightful share of the Iatan 2 coal credits are:

1. When Aquila learned of KCPL's plan to apply for the Iatan 2 Qualifying Advanced Coal Project Credit in 2007, prior to the July 14, 2008 acquisition of Aquila by Great Plains Energy, Aquila should have exercised its claim to these tax benefits by applying to the Department of Energy and the Internal Revenue Service.

2. When Great Plains Energy and KCPL learned of the dispute with Empire in the fall of 2008, shortly after the Aquila acquisition, and Empire made its claim to the Iatan 2 qualifying advanced coal Project credit, Great Plains Energy and KCPL should have included GMO in the resolution of this dispute.

3. When Great Plains Energy and KCPL learned that the IRS considered the Coal Credits for Iatan 2 as being awarded on an Iatan 2 Project basis, rather than on an individual owner basis, Great Plains Energy and KCPL should have included GMO (and Empire) in the allocation of Tax Credits.

4. Great Plains Energy and KCPL should have included GMO in the Arbitration process with Empire in the fall of 2009.

5. After the Arbitration decision on December 30, 2009, Great Plains Energy and KCPL should have included GMO in the request made to the IRS for reallocation of the Iatan 2 Coal Credits.

6. During the discussions with the IRS regarding the request to allocate the Iatan 2 Tax Credits to Empire in early 2010, Great Plains Energy and KCPL should have included GMO in this reallocation process and not signed away GMO's rights to these tax benefits.

If Staff's alternative treatment of disallowing the officer salaries of Great Plains Energy, KCPL and GMO is adopted by the Commission, the Staff's recommended amounts of disallowed officers' salaries and benefits are $618,857 for MPS and $269,445 for L&P. The disallowance would be excluded from cost of service over the life of Iatan 2—approximately a 47-year period of time.

If the Commission does not agree with either allocating a proportional share of the coal credits to GMO or with removing officers salaries and benefits from MPS and L&P costs of service, as another alternative, Staff recommends the Commission consider the imprudence of Great Plains Energy, KCPL and GMO regarding the qualifying advanced coal project credit when it determines what return on equity would be reasonable for both KCPL and GMO in these rate cases.

Issue

In 2008, the Internal Revenue Service (IRS) and the Department of Energy (DOE) approved a $125 million income tax credit – known as Department of Energy Section 48A Qualifying Advanced Coal Project Credit – for the Iatan 2 generating unit project. Iatan 2 is jointly owned by KCPL, GMO (formerly Aquila), Empire, Missouri Joint Municipal Electric Utility Commission ("MJMEUC") and Kansas Electric Power Cooperative, Inc. ("KEPCO"). KCPL did not include either of the other tax-paying owners of Iatan 2 -- Aquila (prior to the acquisition), GMO and Empire -- in the DOE and IRS application for these coal credits. Empire later pursued the qualifying advanced coal project credit through arbitration and received its 12% ownership share of these tax credits. Prior to the arbitration process, both Empire and GMO applied to DOE and IRS for additional coal credits but both applications were rejected. The IRS indicated that all the coal credits had been allocated to the Iatan 2 project and this project had received the maximum credits.

The matter of the appropriate allocation of coal credits between KCPL and GMO was presented as an issue before the Commission in KCPL's and GMO's 2010 rate cases (Case Nos. ER-2010-0355 and ER-2010-0356, the "2010 rate cases"). The Commission ordered KCPL and GMO to request from the IRS a re-allocation of the tax credit for GMO (see March 16, 2011 Order in Case Nos. ER-2010-0355 and ER-2010-0356).

The Commission's March 16, 2011 Order stated in a unanimous decision:

> No later than April 5, 2011, GMO and KCPL shall apply, at the shareholders' expense, to the Internal Revenue Service for an amendment of the Memorandum of Understanding that would allow KCP&L Greater Missouri Operations Company to obtain a share of the Section 48A tax credits for Iatan 2, Section 48A tax credits equal to $26,500,000.

The $26,500,000 amount was corrected in the Commission's March 30, 2011, Order to $26,562,000. The original amount was identified in testimony, upon which the Commission relied, as a rounded amount.

KCPL and GMO sent a letter to the IRS on April 5, 2011, the date the Commission had required KCPL to provide this letter to the IRS, requesting the allocation of the Qualifying Advanced Coal Credits to GMO (s*ee* Appendix 3, Highly Confidential Schedule CGF 1) [Data Request No. 0669, ER-2010-0355].

The IRS rejected the request to allocate any of the Qualifying Advanced Coal Project Credit to GMO on August 24, 2011 (*see* Appendix 3, Highly Confidential Schedule CGF 2). ** ____

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KCPL, a member of the IRS, and Staff held a conference call on September 21, 2011 to discuss why the IRS denied KCPL and GMO's request for allocation of the qualifying advanced coal project credit to GMO. Staff compiled notes from this meeting which are attached as Appendix 3, Highly Confidential Schedule CGF 3.

During the discussion with the IRS representative, Staff ask ** ____ **

At the time of filing this direct testimony, neither Great Plains; KCPL, nor GMO has made any further application to the IRS requesting an allocation be made for GMO. As part of Staff's recommendation it is requesting the Commission order Great Plains Energy along with KCPL and GMO to reapply with IRS requesting a further amendment to Memorandum of Understanding to include an allocation of these coal credits to GMO.

The Commission reached a unanimous decision regarding the Tax Credits in its Order in Case Nos. ER-2010-0355 and ER-2010-0356 dated March 16, 2011:

> Although the Commission is not bound by the decision of the arbitration panel, the Commission accepts the findings of the arbitration panel. Even though each party under the Iatan 2 Agreement was responsible for paying and filing its own taxes, **as the operator of Iatan KCPL owed a special duty to its co-owners. KCPL should have advised GMO and the other co-owners of its intent to request the availability of Section 48A**

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> **credits and of its lobbying efforts to amend the law so that Iatan 2 qualified for the tax credits.** The tax credits in the amount of $125 million were certainly significant to the operation and construction of the facility, and were obviously part of KCPL's operations strategy.
>
> In addition, once arbitration proceedings had begun, GMO should have been involved, in order to protect its own interest. It is clear that even though KCPL may not have realized it at the time, KCPL could not adequately represent the interest of GMO in the arbitration proceedings.
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> ****
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> Since Great Plains Energy and its affiliates file joint tax returns it does not matter to the shareholders whether KCPL or GMO has the tax credits. But, which company has the tax credits can make a difference to the ratepayers because it may affect the cost of service. If the advanced coal tax credits are imputed to GMO it will lower the cost of GMO to serve its customers and, therefore, lower GMO rates.
>
> [emphasis added]

The Commission clarified its March 16, 2011 Order on March 30, 2011 wherein it changed the above wording in its Findings of Fact 24 in the March 16 Order from "imputed to GMO" to "allocated to GMO."

The Commission recognized in its March 16 Order that GMO and the other co-owners should have been informed of KCPL's intent of applying for these Coal Credits.

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When asked if KCPL informed the other owners about the Iatan 2 coal credits, KCPL informed Staff that the other Iatan 2 owners were viewed as "competitors" for the finite amount of monies available for these credits. KCPL did not inform any of the other owners except GMO (named Aquila at the time) about KCPL's application with the DOE and IRS regarding the Iatan 2 coal credits. KCPL informed GMO about the coal credits because of the pending acquisition agreement.

Analysis

These tax benefits relating to the construction and operation of the newly constructed Iatan 2 coal-fired generating unit became available when Congress enacted the Energy Policy Act of 2005 (the "2005 Energy Act"), signed into law on August 8, 2005. The 2005 Energy Act provided the opportunity for owners of newly constructed power plants burning clean coal and meeting certain emission standards to apply with the Department of Energy and the Internal Revenue Service for qualifying coal credits. These coal credits were called Section 48A Qualifying Advanced Coal Project Credit (herein referred to as the "Iatan 2 Credits," "Tax Credits," "Coal Credits" or "Section 48A Credits").

In 2006 and 2007, KCPL applied with the IRS and DOE for coal credits relating to the 850 megawatt Iatan 2 coal-fired generating unit. KCPL first applied for coal credits in 2006 without informing any of the other Iatan 2 owners, but was initially denied because the plant did not qualify. KCPL lobbied Congress for a change in law so Iatan 2 would qualify for credits and the law was subsequently changed. KCPL then re-applied for the coal credits in 2007 and the Iatan 2 project was successful with this re-application. At the time of its re-application, KCPL informed Aquila that it was applying for the Iatan 2 coal credits because of the pending acquisition of Aquila (now GMO) by KCPL's parent, Great Plains Energy. Aquila did not pursue the coal credits when it learned of the existence of such credits.

After the July 14, 2008 acquisition of Aquila by Great Plains Energy, GMO applied for the coal credits in an application dated October 30, 2008—this GMO application for the Iatan 2 coal credits is attached as Appendix 3, Highly Confidential Schedule CGF 4. ** ____

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On April 28, 2008 KCPL was notified by the IRS that KCPL's application had been successful in qualifying for Iatan 2 Advanced Coal Project Credits (*see* Appendix 3, Highly Confidential Schedule CGF 5). The IRS indicated the Iatan 2 project was allocated $125 million. The IRS stated that "based on the information supplied in your [KCPL] application, we [the IRS] have accepted the Project's application and have allocated $125,000,000 of Section 48A credit to the Project." It is clear from this communication that the qualifying advanced coal project credit was for Iatan 2 Project, not for KCPL, or at least it should have been clear. KCPL entered into its original Memorandum of Understanding with the IRS dated August 26, 2008 (see Appendix 3, Highly Confidential Schedule CGF 5) regarding the receipt of the $125 million amount of the Iatan 2 Project Coal Credits [source: Data Request No. 0866—ER-2009-0089]. The August 2008 Memorandum of Understanding with KCPL would later be amended on August 19, 2010 to include allocating a portion of the qualifying advanced coal project credit for Iatan 2 to Empire.

A. Iatan 2 Qualifying Advanced Coal Project Credit

Introduction/Recommendations

The coal credit application was evaluated by DOE and the IRS based on the size of the generating unit and its meeting certain qualifying environmental emission standards. Additionally, in order to meet the advanced clean coal standards and avoid forfeiture and/or the recapture of credits in the future, Iatan 2 must meet or exceed certain qualifying environmental performance requirements for at least five years, once the plant went into service.

Iatan 2 is co-owned by KCPL, GMO, Empire, Missouri Joint Municipal Electric Utility Commission (MJMEUC) and Kansas Electric Power Cooperative, Inc. (KEPCO). In KCPL's application to the Department of Energy dated October 30, 2007 (s*ee* Appendix 3, Highly Confidential Schedule CGF 6), KCPL supplied the following information relating to the ownership of Iatan 2:

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[source: page 12 KCPL application October 30, 2007- Department of Energy Section 48A Certification Application for Advanced Coal Project Credits—Data Request 135, Case No. ER-2010-0355]

Each of the ownership shares represented an amount of megawatt (MW) capacity and, ultimately, its related energy output based on this megawatt capacity, as follows:

Utility	**Ownership Share**	**Megawatt Capacity**
KCPL	54.71%	465 MW
GMO (former Aquila)	18%	153 MW
Empire District Electric	12%	102 MW
Missouri Joint Municipal Electric Utility Commission	11.76%	100 MW
Kansas Electric Power Cooperative, Inc.	3.53%	30 MW
Total	100%	850 MW

On October 9, 2008, KCPL was notified by Empire of Empire's view that a portion of the qualifying advanced coal project credit previously awarded to KCPL should be allocated to Empire. The Notice of Controversy (*see* Appendix 3, Highly Confidential Schedule CGF 7-4) served as written notice to KCPL of the dispute pursuant to Section 12.1 of the IATAN UNIT 2 AND COMMON FACILITIES OWNERSHIP AGREEMENT.

On November 21, 2008, KCPL's president, William H. Downey, responded to Empire that KCPL would not agree to allocate Empire a share of the Qualifying Advanced Coal Project Credits- the "Tax Credits" (*see* Appendix 3, Highly Confidential Schedule CGF 7-9). Mr. Downey stated:

** ____ **

On July 10, 2009, KCPL was served a Notice to Arbitrate (*see* Appendix 3, Highly Confidential Schedule CGF 7-12) by Empire and the remaining co-owners of Iatan 2 (other than GMO, which was now owned by Great Plains), KEPCO and MJMEUC. The co-owners contended that they were entitled to receive proportionate shares (or the monetary equivalent) of the $125 million advanced coal project credits for Iatan Unit 2.

In November 2009, this matter was heard by a three person arbitration panel. On December 30, 2009, the arbitration panel, convened pursuant to Article XII of the Iatan Unit 2 And Common Facilities Ownership Agreement, issued a unanimous decision ordering KCPL and Empire to jointly seek a reallocation of the tax credits giving Empire its representative share of the total tax credits based on Empire's 12% ownership of Iatan 2, and worth approximately $17.7 million in tax credits to Empire (the Final Arbitration Award is herein referred to as the "Arbitration Order" — see Appendix 3, Highly Confidential Schedule CGF 8). The December 30 Arbitration Order denied KEPCO's and MJMEUC's claims to the Tax Credits. The Arbitration Order further specified that if the IRS denied KCPL and Empire's reallocation request, or if Empire was allocated less than its proportionate share of the tax credits, KCPL would be responsible for paying Empire the full value of its representative percentage of the tax credits (less the amount of tax credits, if any, Empire ultimately received) in cash.

The following are excerpts from the Arbitration Order:

> KCPL planned to apply for the Section 48A tax credits with respect to Iatan 2 even before it negotiated the Ownership Agreement with the other Owners; yet it told none of them. In August, 2006, KCPL filed applications with the IRS and the US Department of Energy ("DOE") requesting that the Iatan 2 project be certified by the DOE as meeting the requirements set forth in Section 48A. The application was not successful. KCPL did not tell any of the other Owners that it had made this filing, nor did it discuss with them whether they should or could have filed an application at the same time or whether KCPL and some of the other Owners could have filed a joint application. These actions of KCPL constituted willful misconduct.
>
> Once KCPL's initial application for the Section 48A tax credits was denied, KCPL lobbied for an amendment to Section 48A to allow Iatan 2 to qualify for such credits. KCPL did not tell any of the other Owners that it was doing so nor did KCPL tell any of the other Owners that it had hired a contractor and, in turn, a subcontractor to assist in determining whether Iatan 2 qualified under the amended statute. As Operator, KCPL had a duty to inform the other Owners of its efforts to determine whether Iatan 2 qualified for the Section 48A credits and what impact that would have on the construction of Iatan 2. Again, these actions of KCPL constituted willful misconduct.
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> * * * *
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> Despite not having told any of the other Owners of its efforts to investigate whether Iatan 2 would qualify for the Section 48A credits, and despite not having given the other Owners the opportunity to file a joint application or apply on their own behalf, KCPL nonetheless charged the other Owners for the costs of (a) evaluating whether Section 48A credits would be available and (b) applying for the Section 48A credits. In fact, KCPL charged the other Owners for the cost of investigating whether Iatan 2 would qualify for the credits, but it never informed the other Owners of the investigation, the results thereof or its own application for the credits.
>
> During the period in which it was investigating whether Iatan 2 would qualify for the Section 48A credits and thereafter in 2006 and 2007 when it was applying for the credits, KCPL did not inform any of the other Owners of its investigation, nor did it have any discussions with Empire, KEPCO or MJMEUC regarding the Section 48A credits or the applications with the IRS and DOE. KCPL did, however, discuss the Section 48A credits with co-Owner GMO, which was subsequently acquired by KCPL's parent company.

The actions of KCPL constituted "willful misconduct" in that KCPL acted willfully and in an opportunistic manner to garner all of the benefits of the Section 48A credits for itself while billing the other Owners for their share of certain costs incurred in qualifying the project for such credits and thereafter applying for the credits (at the same time it was sharing its plan with co-Owner GMO, with whom it would soon be affiliated). KCPL's actions also clearly constituted a breach of the implied duty of good faith and fair dealing imposed by Missouri contract law.

KCPL has not made any payments to the other Owners with respect to the tax benefits, if any, it has received as a result of obtaining the Section 48A credits.

Based on the foregoing, it is the unanimous opinion of the Arbitration Panel that:

(1) KCPL breached Sections 4.1, 5.3(a), 6.5(d) and 21.1 of the Ownership Agreement, and also the implied duty of good faith and fair dealing, by evaluating the project's eligibility for, and applying for, Section 48A credits without bringing these matters to the attention of the other Owners;

(2) Empire sustained damages as result of KCPL's breach of Sections 4.1, 5.3(a), 6.5(d) and 21.1 of the Ownership Agreement (and also the implied duty of good faith and fair dealing), due to the fact that such breach prevented Empire from successfully applying for its fair share of Section 48A credits allocated to the project.

* * * *

Accordingly, IT IS HEREBY ORDERED:

(1) KCPL and Empire shall apply to the IRS for an amendment of the MOU that would allow Empire to obtain a share of the Section 48A tax credits equal to $17,712,500. If the IRS approves such an amendment to the MOU, then no further relief is required for Empire.

(2) If the application to amend the MOU is denied, or if Empire is allocated less than $17,712,500 in Section 48A tax credits under the amended MOU, then KCPL shall immediately pay the following amount to Empire: $17,712,500, less the amount of Section 48A tax credits, if any, allocated to Empire under the amended MOU.

(3) If it has not already done so, KCPL shall pay to KEPCO and MJMEUC, immediately, any amounts previously paid by KEPCO and MJMEUC with respect to the costs incurred by KCPL in (a) determining whether the Iatan 2 project qualified for the Section 48A credits, (b) working to amend Section 48A in order to ensure that the Iatan 2 facility qualified for the Section 48A credits and (c) applying for the

> Section 48A credits. Empire shall not be entitled to receive any such payment from KCPL.
>
> (4) Claimants' (and, if applicable, KCPL's) requests for attorneys' or experts' fees, costs, carrying, charges and interest are hereby denied.
>
> (Emphasis added; pages 3-5 of the Arbitration Order).

Selected pages that identifies Sections 4.1, 5.3(a), 6.5(d) and 21.1 from the May 19, 2006 Iatan Unit 2 and Common Facilities Ownership Agreement are attached as Appendix 3, Schedule CGF 9.

All of the Arbitration Panel's statements regarding and characterizations of KCPL's conduct regarding the issue of receipt by Empire of its rightful proportionate share of the coal credits apply with equal force to the other investor-owned co-owner of the Iatan 2 unit, GMO. However, as GMO was owned by Great Plains Energy at the time of the arbitration decision, GMO was not allowed by Great Plains Energy to act in its own and its customers' best interest and seek to obtain its rightful proportionate share of the coal credits.

In early 2010, KCPL and Empire requested a reallocation of the Tax Credits from the IRS pursuant to the Arbitration Order. Empire received its share of the Coal Credits through a revised Memorandum of Understanding from the IRS dated August 19, 2010. (*see* Appendix 3, Highly Confidential Schedule CGF 10-5)

The reallocation changed the amount allocated to KCPL as follows:

	Original Memorandum of Understating	Revised Memorandum of Understanding
KCPL	$125,000,000	$107,287,500
Empire	$0	$ 17,712,500
Total	$125,000,000	$125,000,000

If GMO had been included in the reallocation of the $125 million amount of Coal Credits based on its 18% ownership share, Empire's allocated amount would remain the same but KCPL's share would be further reduced as follows:

	Original Memorandum of Understating	Revised Memorandum of Understanding	Reallocation including GMO
KCPL	$125,000,000	$107,287,500	$80,725,000
Empire	$0	$17,712,500	$17,712,500
GMO	$0	$0	$26,562,500
Total	$125,000,000	$125,000,000	$125,000,000

The three member arbitration panel determined that KEPCO and MJMEUC were not eligible to share in any of the Iatan 2 Coal Credits because they both were non-taxpayers. The Arbitration Panel found:

> (3) Despite KCPL's breach of Sections 4.1, 5.3(a), 6.5(d) and 21.1 of the Ownership Agreement (and the implied duty of good faith and fair dealing), KEPCO and MJMEUC have no right to claim tax credits under Section 48A. Section 50(b)(3) of the Internal Revenue Code states that no credit shall be determined under Subpart E with respect to any property used by an organization which is exempt from tax, unless such property is used predominately in an unrelated trade or business. Under this provision, KEPCO could not have applied for or obtained tax credits under Section 48A with respect to KEPCO's investment in the project. Further, Section 50(b)(4)(A) states that no credit shall be determined under Subpart E with respect to any property used by a political subdivision of any state. Under this provision, MJMEUC could not have applied for or obtained tax credits under Section 48A with respect to MJMEUC's investment in the project…
>
> [Source: Arbitration Award decision- page 4, item (3)]

The Arbitration Panel concluded that although "…KCPL engaged in willful and opportunistic misconduct…" respecting its dealings with KEPCO and MJMEUC regarding the Coal Credits, it could not grant the relief requested by these two non-taxpaying owners.

After KCPL and Empire requested the IRS to reallocate a portion of the Coal Credits to Empire pursuant to the Arbitration Order, and before they received the revised Memorandum of Understanding from the IRS dated August 19, 2010, ** ________________________________

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Attached to the May 3, 2010 letter to the IRS, an officer of Great Plains Energy, KCPL, and GMO signed Declarations Under Penalties of Perjury on behalf of both Great Plains Energy and GMO. The Declaration Under Penalties of Perjury was signed by Terry Bassham, then Great Plains Energy's Executive Vice President- Finance and Strategic Development and Chief Financial Officer. Mr. Bassham also signed for GMO as the Executive Vice President- Finance and Strategic Development and Chief Financial Officer:

** **

Mr. Bassham was appointed by the Great Plains Board of Directors in 2012 as Chief Executive Officer effective June 1, 2012.

GMO, having no independent voice, could not object to the waiving of its right to the Tax Credits. This final act in the spring of 2010 was the culmination of all the negative actions and failures to act which face the Commission in its attempt to solve the adverse detriments placed upon GMO and its customers by not receiving GMO's rightful share of the tax benefits derived from the construction and operations of Iatan 2. All costs relating to the environmental equipment which was installed that allowed Iatan 2 to qualify for the clean coal tax credits were paid initially by Aquila and, after the acquisition, by GMO on an 18% ownership basis. Yet, despite several opportunities to correct the misconduct, Great Plains Energy and KCPL engaged in opportunistic behavior that deprived GMO its proportionate share of these tax benefits. The IRS would have been indifferent if GMO had been included in the allocation request at the time when Empire made its request. The Arbitration Panel would also have had no reason to exclude GMO from an allocated share of the tax benefits based on its 18% ownership interest. Indeed, fairness would have prevailed and GMO, like Empire, would have been allocated 18%, or $26,562,500 worth of credits, representing its ownership share of the total $125 million in credits awarded to the Iatan 2 Project.

1. <u>Iatan 2 Costs and Iatan 2 Benefits</u>

During the construction of Iatan 2 and each month of operation throughout its service life, KCPL invoiced and will continue to invoice each owner its proportionate share of costs to build and operate the unit. The owners, including GMO (Aquila pre-acquisition), are required to reimburse KCPL for these costs based on the Iatan 2 Operating Agreement. All costs to construct and operate Iatan 2 are expected to be paid by the co-owners of this generating facility and, conversely, all benefits derived from Iatan 2 are expected to be given to the owners. The owners of this unit all share in the benefit of the low-cost production of electricity based on the proportionate ownership share of each. In the case of the Tax Credits, the tax-paying owners should all share in the proportional ownership of the $125 million in awarded Tax Credits. Empire received approximately $17.7 million of the Tax Credits and GMO has yet to receive any of these tax benefits. Staff recommends that GMO should be authorized $26,562,500 million based on its ownership share of the total $125 million Tax Credits awarded the Iatan 2 Project.

KCPL engaged in "willful misconduct" and was imprudent with respect to not including GMO when KCPL first learned of the dispute with Empire; not including GMO in the 2009 Arbitration process; not including GMO in the request for reallocation of the Tax Credits after the Arbitration Panel decided that Empire should have been included in the allocation of the Tax Credits; and in affirmatively waiving or signing-away GMO's right to claim any allocation of Tax Credits from the IRS.

2. <u>Kansas City Power & Light Company's Obligations to KCP&L Greater Missouri Operations Company</u>

After the July 14, 2008 acquisition of Aquila's Missouri electric properties by Great Plains, KCPL entered into an agreement with GMO dated October 10, 2008 (herein referred to as the "Joint Operating Agreement") to provide operational services, including tax services, to GMO. All former Aquila employees retained by Great Plains were transferred to KCPL. As such, GMO does not have any employees. Through the Joint Operating Agreement, KCPL is obligated to provide all activities necessary to operate, maintain, plan, direct and oversee GMO (*see* Appendix 3, Schedule 12).

The Joint Operating Agreement was signed on behalf of both KCPL and GMO by the same KCPL officer, William H. Downey, President and Chief Operating Officer of KCPL and President and Chief Operating Officer of Aquila, Inc., doing business as KCP&L Greater Missouri Operations. William G. Riggins, General Counsel and Chief Legal Officer for KCPL and Aquila, Inc., doing business as KCP&L Greater Missouri Operations, also signed the Joint Operating Agreement representing both KCPL and GMO.

Since GMO has no employees, KCPL is identified as GMO's Designated Agent and Operator. Section 1.2 of the Joint Operating Agreement states:

> Section 1.2 KCP&L Designated Agent and Operator. KCP&L GMO hereby designates KCP&L as its agent and operator of its business and properties. KCP&L shall be responsible for and shall perform, through its employees, agents, and contractors, all such actions and functions (including, without limitation, the entry into contracts for the benefit of or as agent for KCP&L GMO) as may be required or appropriate for the proper design, planning, construction, acquisition, disposition, operation, engineering, maintenance and management of KCP&L GMO's business and properties in accordance with the terms of this Agreement (the "Services"). KCP&L GMO hereby delegates to KCP&L, and KCP&L hereby accepts responsibility and authority for the duties set forth in this Agreement.

The Joint Operating Agreement identifies how KCPL is to treat GMO in making operational decisions. Section 1.8 of the Joint Operating Agreement between KCPL and GMO states:

> Section 1.8 Parity of Services and Internal KCP&L Operations. KCP&L will at all times use its commercially reasonable efforts to provide the Services in scope, quality and schedule equivalent to those it provides to its own internal operations. In providing the Services, **KCP&L will seek to maximize the aggregate synergies to both companies, and shall not take any action that would unduly prefer either party over the other party.** (emphasis added)

In defining Services that KCPL provides to GMO, Section 1.3 of the Joint Operating Agreement states:

> Section 1.3 Description of the Services. The Services shall include all services required or appropriate for the design, planning, construction, acquisition, disposition, operation, engineering, maintenance and management of KCP&L GMO's business and properties. The Services exclude wholesale electricity and transmission service transactions between KCP&L and KCP&L GMO, which will be governed by applicable Federal Energy Regulatory Commission ("FERC") tariffs and rules…

Appendix A to the Joint Operating Agreement more fully describes the Services KCPL is required to provide GMO. Appendix A – Description of Services identifies the Services as:

> General descriptions of the Services to be provided by KCP&L to KCP&L GMO are detailed below. The descriptions are deemed to include services associated with, or related or similar to, the services contained in such descriptions. The descriptions are not intended to be exhaustive, and KCP&L will provide such additional services, whether or not referenced below, that are necessary or appropriate to meet the service needs of KCP&L GMO.

Under the category "Income and Transaction Taxes" the Joint Operating Agreement states KCPL is:

> Responsible for all aspects of maintaining the tax books and records of all Great Plains Energy entities, including KCP&L GMO. Tax services can be categorized in five major functions providing the primary services as follows: prepare, review and file all consolidated and separate federal, state and local income, franchise, sales, use, gross receipts, fuel excise, property and other miscellaneous tax returns and payments; research tax issues and questions, including interpretation of rules and proceedings, develop short and long range planning for all types of taxes and monitor and review new or proposed tax laws, regulations, court decisions and industry positions; provide tax data for budget estimates and rate cases, provide reports of tax activity and projected cash requirements and prepare, review and record tax data for financial reports; supervise and review tax audit activities; respond to vendor-related tax matters associated with tax compliance or tax saving opportunities and process customer tax refunds and adjustments to customer accounts.

The Joint Operating Agreement between KCPL and GMO is included as Appendix 3, Schedule CGF 12.

In effect, GMO (as the former Aquila entity) lost all ability to make any decisions independently from KCPL, to advocate its own self-interest, and to defend itself from decision-making that was not in its best interest. The Joint Operating Agreement required KCPL to always make decisions regarding the operations of GMO that are in the best interest of GMO in that "**KCP&L will seek to maximize the aggregate synergies to both companies, and shall not take any action that would unduly prefer either party over the other party.**" (Section 1.8 of Joint Operating Agreement)(emphasis added).

In the case of the Tax Credits, GMO had no voice to raise its objections that it was excluded from participation in the Arbitration process or to request a reallocation of the Tax Credits from the IRS at the time when Empire made such request. While KCPL could not silence Empire, it had complete control over ensuring GMO did not receive any benefit from the Tax Credits. In this instance, KCPL has not fulfilled its obligation as GMO's "agent and operator of its business and properties" (Section 1.2 of Joint Operating Agreement).

The Great Plains Energy officers are the same as the officers for KCPL and GMO. All officers of KCPL are also officers of GMO. All the Board of Directors of Great Plains Energy are also Board members of KCPL and GMO with the exception of one.

No independent voice can be found in the entire organization of Great Plains Energy and its wholly-owned affiliates—KCPL and that could promote, support and defend any decision by GMO to pursue its rightful share of the Iatan 2 coal credits.

3. Iatan 2 Coal Credits Are an Acquisition Detriment

On April 4, 2007, Great Plains, KCPL, and Aquila, Inc. ("Aquila"), filed a joint application with the Commission, designated as Case No. EM-2007-0374, requesting approval for a series of transactions which ultimately would result in Great Plains acquiring Aquila's Missouri electric and steam operations, as well as its merchant services operations. The Commission approved the joint application in an Order effective July 1, 2008. Great Plains acquired Aquila on July 14, 2008 and later in 2008, Aquila changed its name to KCP&L Greater Missouri Operations Company ("GMO").

GMO had no voice to request the Coal Credits for its ownership share of Iatan 2 because of the acquisition by Great Plains. Since KCPL is the only Great Plains entity which has employees, KCPL did not allow GMO to participate in the arbitration process and also did not include GMO when it made a request to the IRS for the reallocation to Empire. Absent the acquisition, Aquila (GMO) would have been in position to take part in the arbitration process and, more importantly, it would have requested a share of the Coal Credits when the IRS was requested to reallocate Coal Credits to Empire. Because the acquisition gave Great Plains and KCPL complete control over the operations of GMO, including all decisions regarding the Coal Credits, GMO could not request to participate in the allocation of these credits, much less defend itself against KCPL's insistence that the Coal Credits belonged solely to KCPL. After the Aquila acquisition, KCPL represented the interests of GMO, or in the case of the Coal Credits, KCPL ensured that GMO could not participate in any respect in seeking an allocation of these credits. The acquisition provided KCPL the opportunity to speak for GMO which, with regard to the Coal Credits, gave KCPL the opportunity to silence GMO. If Aquila had not been acquired by Great Plains, Aquila would have had the same opportunity as Empire to pursue the Coal Credits. Aquila – like Empire – would have been awarded its proportionate share of the Coal Credits had it been allowed to participate in the arbitration process and the request to the IRS to reallocate the $125 million coal credits among KCPL, Empire and Aquila based on the ownership share of each.

In the acquisition application filed in Case No. EM-2007-0374, the applicants indicated that the acquisition of Aquila by Great Plains Energy would not result in a detriment to the public. GMO losing its ability to make independent decision-making regarding the qualifying advance coal credits that would be in GMO and its customers' best interest is an acquisition detriment. GMO lost its ability to speak for itself and was disadvantaged in doing so. KCPL capitalized on an opportunity to seek the benefits of the coal credits at the expense of GMO. The Commission should not let this happen and ensure the benefits of these coal credits are available to GMO just as those benefits are available to KCPL.

Staff Expert/Witness: Cary G. Featherstone

XIII. Jurisdictional Allocations

The Missouri Public Service Commission sets cost-of-service based rates only for the Missouri retail customers; however, not all the costs a utility incurs are necessarily to provide service to its Missouri retail customers. GMO has both retail and wholesale customers; however, it only serves wholesale customers in the area in which MPS rate schedules apply. GMO has no electric wholesale customers in the area in which L&P rate schedules apply. Because GMO has no electric wholesale customers in the area in which L&P rate schedules apply, there is no Federal Energy Regulatory Commission ("FERC") wholesale jurisdiction to consider in the revenue requirement calculation for L&P. Wholesale and retail sales are considered to be in separate "jurisdictions." Because the MPS and L&P rates differ, Staff considers them separately and independently when developing jurisdictional allocators. Some costs to serve a particular jurisdiction may be directly assigned; however, other costs are not directly assignable to a particular jurisdiction and must therefore be allocated among the various jurisdictions. Costs that correlate with energy-generally costs that vary with energy consumption-are denoted as "energy-related" costs. Costs that correlate with demand-generally costs that do not vary with energy consumption, i.e. "fixed costs"-are denoted as "demand-related" costs. Different allocation factors are developed and utilized for each.

Jurisdictional allocation refers to the process by which demand-related and energy-related costs are allocated to the applicable jurisdictions. Fixed costs, such as the capital costs associated with generation and transmission plant, are allocated on the basis of demand. Variable costs, such as fuel, are more appropriate to allocate on the basis of energy consumption. In this Case, jurisdictional allocation factors for demand and energy are calculated to assist in allocating demand-related (fixed) costs and energy-related (variable) costs between two applicable jurisdictions: retail and wholesale operations for MPS. The application of a particular jurisdictional allocation factor is dependent upon the type of cost being allocated. These calculations were performed for MPS only; they are not necessary for L&P because there are no electric wholesale customers in the L&P area.

Staff Expert/Witness: Alan J. Bax

A. Methodology

1. <u>Demand Allocation Factor</u>

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

Staff utilized a 4CP method - based on the monthly seasonal coincident peaks of the four summer months in the test period - to determine the demand allocation factors for MPS. The 4CP method is appropriate for MPS that experiences dominant demands in the four summer months (June through September) in relation to the demands in the other eight months of a year. Utilizing a 1 CP method may be considered if there was an occurrence of a needle peak in a particular month, or possibly a 12 CP method if comparatively similar hourly peaks were experienced in both winter and summer months. In analyzing the monthly demands in the twelve month period ending March 31, 2012, the period analyzed in the current rate case, these demands are consistent with the monthly demands in the test periods associated with the last several rate cases involving MPS.

Staff determined the demand allocation factor for each jurisdiction using the following process:

a. Identify MPS's peak hourly load in each month for the four - month period June 2011 through September 2011 and sum the hourly peak loads.

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

c. Divide b. above by a. above.

The result is the allocation factor for each jurisdiction:

- Retail: 0.9950
- Wholesale: 0.0050
- Total: 1.0000

Staff Expert/Witness: Alan J. Bax

B. Energy Allocation Factor

Variable expenses, such as fuel, are allocated to the jurisdictions based on energy consumption. The energy allocation factor for each jurisdiction is the ratio of the sum of the total kilowatt-hours (kWh) used by the particular jurisdiction in the test year, the twelve month period ending March 2012, to MPS's total kWh usage during the test year. Staff applied adjustments to these kilowatt hours to account for losses, weather, certain annualizations and customer growth. Weather adjustments were provided by Staff Witness Shawn E. Lange. The annualization adjustments were provided by Staff Witness Curt Wells and the growth adjustment by Staff Witness Karen Lyons. Staff has calculated the following energy allocation factors for each jurisdiction:

- Retail: 0.9946
- Wholesale: 0.0054
- Total: 1.0000

These jurisdictional demand and energy allocation factors were provided to Staff Witness Cary G. Featherstone, who used them to allocate related costs to the Missouri retail jurisdiction.

Staff Expert/Witness: Alan J. Bax

C. Application

As stated above, MPS operates within Missouri, and in the wholesale jurisdiction regulated by the FERC. Therefore, it is necessary to identify, then allocate and/or assign, MPS' specific investments and costs among these two jurisdictions (Missouri Retail and Wholesale). To identify MPS' revenue requirement, Staff must develop MPS' cost of service for its Missouri retail jurisdiction. To do that MPS' plant investments and costs in its income statement must be appropriately assigned or allocated to the Missouri retail jurisdiction.

To develop MPS' cost of service for its Missouri retail jurisdiction, Staff began with MPS' records kept in accordance with FERC accounting requirements per Commission rule. Where these records reflected costs or investments that MPS incurred solely to serve the Missouri retail jurisdiction, Staff directly assigned those costs or investments to 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.

MPS uses its generation and transmission facilities to produce and transport electricity to its Missouri retail customers and wholesale customers (FERC jurisdiction). Because they are primarily sized to meet demand, Staff allocated 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 MPS 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 MPS demand allocators over several rate cases.

In its records kept in accordance with FERC accounting requirements, MPS separately 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 MPS treated distribution plant in its case, Staff used MPS' actual distribution plant investment in Missouri at March 31, 2012 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 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 MPS' income statement (reproduced as Schedule 9 in Staff's Accounting Schedules) include amounts for costs broadly described as production, transmission, distribution, general and administrative and general ("A&G"). Using the expense accounts found in MPS' income statement, this principle that expenses should follow plant investment is appropriate because MPS incurs production (generation) plant expenses to maintain and operate its the generation 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, MPS incurs 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 MPS' investment in its transmission facilities.

Staff allocated MPS' production and transmission costs taken from MPS' income statement to KCPL's Missouri retail jurisdiction with the same demand allocator Staff developed and used to allocate KCPL's investment in generating and transmission facilities to MPS' 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 and the site specific allocation factor. Staff applied the demand allocation factor used to quantify the Missouri jurisdictional share of MPS' production and transmission costs and the site specific allocation factor used to allocate an appropriate part of MPS' total company distribution plant and reserve amounts to MPS' Missouri retail jurisdiction. Staff used the resulting production and transmission plant and depreciation reserve amounts and distribution plant costs allocated to MPS' Missouri retail jurisdiction to form the basis for allocating MPS' general plant to its Missouri retail jurisdiction. Thus, Staff's Missouri retail jurisdiction allocation factor for MPS' 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 MPS' Missouri retail jurisdiction what are described in MPS' income statement (Staff Accounting Schedule 9) as "general" costs.

L&P has only Missouri retail jurisdiction so all its operations are 100% Missouri. However, L&P does have industrial steam operations that cause the need to allocate plant investment and costs between the electric and steam operations. Staff relied on GMO for these allocation factors.

Staff also used a variety of jurisdictional allocation factor to allocate the appropriate part of MPS and L&P's administrative and general costs found in MPS and L&P' income statement (Staff Accounting Schedule 9), to MPS and L&P's 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 MPS and L&P's 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, GMO 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 has used energy allocation factors to allocate off-system sales to KCPL and GMO's Missouri retail jurisdiction in each of KCPL's last four rate cases during its Regulatory Plan and many GMO rate cases dating back to at least the 1990s. Staff also has consistently used energy allocation factors to allocate off-system sales revenues to the Missouri retail jurisdictions of The Empire District Electric Company.

Staff Expert/Witness: Cary G. Featherstone

XIV. Other Miscellaneous Items

A. Demand-Side Management Cost Recovery

Staff recommends that the Commission order the continuation of the current GMO demand-side management ("DSM") regulatory asset account mechanism[89] in this case to allow full recovery of direct program costs for the Company's eight (8) energy efficiency programs, two (2) demand response programs and one (1) affordability program.

GMO had limited DSM programs prior to its acquisition by Great Plains Energy. However, since its acquisition by Great Plains Energy, DSM programs consistent with the DSM programs of KCPL have been successfully implemented in the GMO service territory. Attached to this Staff Report as Schedule JAR-1 are pages from the Staff's second Status Report on Energy Efficiency Advisory Groups and Collaboratives[90] which highlight the GMO DSM stakeholder group process and the challenges and successes to date of the Company's DSM programs. Schedule JAR-1 also includes a brief description of the Company's eleven DSM programs.

GMO continues its practice - started in early 2010 - of not accepting new applications for its large customer MPower demand-response program[91]. GMO currently has about 13 MW of voluntary load curtailment under contract for its MPower program. It is noteworthy that ** ______________________________

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[89] 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 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.

[90] On January 4, 2012, Staff provided to the Commission in File No. AO-2011-0035 its second annual Status Report concerning all of the Missouri investor-owned natural gas and electric utilities' demand-side programs advisory groups and collaboratives.

[91] MPower Rider contained in GMO tariff sheets P.S.C.MO. No. 1, Sheet Nos. 128, 129, 130, 131 and 132.

The energy and capacity impacts and the overall delivery processes of GMO's DSM programs are evaluated, measured and verified by third-party contractors of the Company and copies of completed evaluation, measurement and verification ("EM&V") reports will be provided to the GMO DSM Advisory Group members. All GMO DSM programs have had at least one EM&V report with both process and impact evaluations.

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 File No. ER-2010-0356 directs 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."[92]

Staff recommends that the Commission order the continuation of the current GMO DSM regulatory asset account mechanism in this case.

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

1. Missouri Energy Efficiency Investment Act of 2009 ("MEEIA")

The MEEIA was established in Senate Bill 376[93] and became law on August 28, 2009. The Commission's MEEIA rules[94] became effective May 30, 2011. With the passage of Senate Bill 376 and the enactment of the MEEIA, the State of Missouri has declared and directed the following:

> 3. It shall be the policy of the state to value demand-side investments equal to traditional investments in supply and delivery infrastructure and allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs. In support of this policy, the commission shall:
>
> (1) Provide timely cost recovery for utilities;
>
> (2) Ensure that utility financial incentives are aligned with helping customers use energy more efficiently and in a manner that sustains or enhances utility customers' incentives to use energy more efficiently; and
>
> (3) Provide timely earnings opportunities associated with cost-effective measurable and verifiable efficiency savings.
>
> 4. The commission shall permit electric corporations to implement commission-approved demand-side programs proposed pursuant to this section with a goal of achieving all cost-effective demand-side savings. Recovery for such programs shall not be permitted unless the programs are approved by the commission, result in energy or demand savings and are beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers.[95]

On December 22, 2011, GMO filed in File No. EO-2012-0009 its *Application for Approval of Demand-Side Programs and for Authority to Establish A Demand-Side Programs Investment Mechanism* in which the Company requested Commission approval of a 3-year program plan for the majority of its existing DSM programs and five new DSM programs as MEEIA programs. GMO also requested Commission approval of a demand-side programs investment mechanism ("DSIM") rider pursuant to MEEIA and the Commission's MEEIA rules. GMO's requested DSIM rider includes the following features and components: 1) DSIM rates for all customer classes except Lighting, 2) a cost recovery component, 3) a shared benefits component, 4) a performance incentive component, 5) a lost revenue component, and 6) an opt-

[93] Section 393.1075, RSMo. Supp. 2011.
[94] The Commission's MEEIA rules include: 4 CSR 240-3.163, 4 CSR 240-3.164, 4 CSR 240-20.093 and 4 CSR 240-20.094.
[95] Subsections 393.1075.3 and 4, RSMo. Supp. 2011.

out provision. GMO's MEEIA application presents the first opportunity to significantly change the regulatory framework for GMO to begin to achieve the Missouri Legislature's vision stated in the MEEIA.

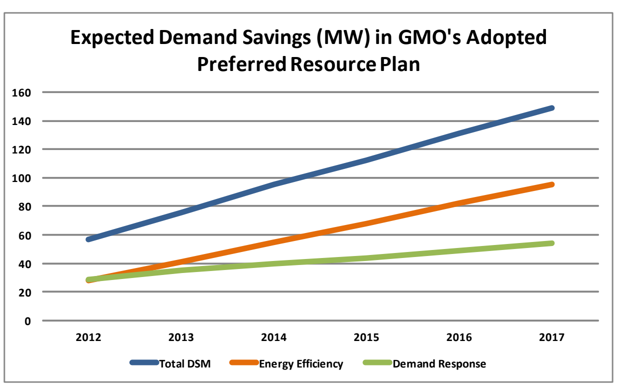
Rebuttal and surrebuttal testimony were filed on March 20, 2012 and May 10, 2012, respectively. However, hearings, originally scheduled for May 29, 30 and 31 and June 1, 2012, were reset for July 9 – 11, 2012. Then, on July 5, 2012, the hearings were continued indefinitely to allow parties the opportunity to conduct confidential settlement discussions for this case. At this time, the confidential settlement discussions are ongoing. Should the parties reach an agreement prior to the submission of this case, Staff will update its testimony in this case accordingly.

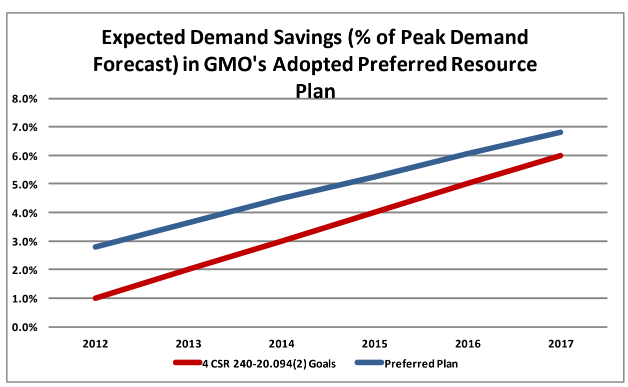
[*Initial version contained text included in error]*

[Initial version contained text included in error]

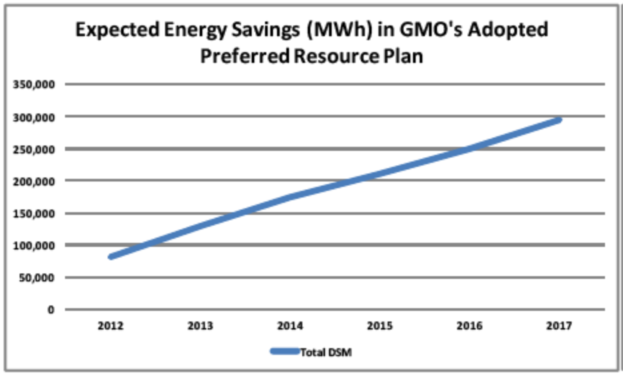
2. <u>Demand-Side Resources in Adopted Preferred Resource Plan</u>

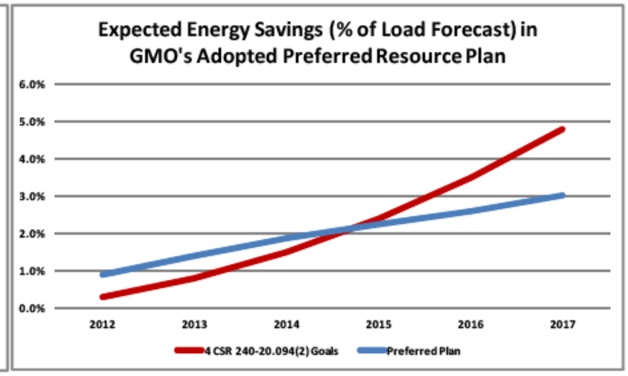
On April 9, 2012, GMO filed its Chapter 22 Electric Utility Resource Planning triennial compliance filing in File No. EO-2012-0324. GMO's adopted 20-year preferred resource plan includes 19 MW of solar additions, 350 MW of wind additions, 450 MW of combined cycle additions, the 2016 retirement of the 99 MW Sibley Units 1 and 2, and a portfolio of demand-side resources. The following charts show: 1) the expected annual demand savings (MW) due to the Company's two (2) demand response programs and twelve (12) energy efficiency programs, and 2) the expected cumulative annual demand savings as a percentage of forecasted annual peak demand and the "soft goals" for cumulative annual demand savings in the Commission's Rule 4 CSR 240-20.094(2).





The following charts show: 1) the expected annual energy savings (MWh) due to the Company's twelve (12) energy efficiency programs, and 2) the expected cumulative annual energy savings as a percentage of annual load forecasted and the "soft goals" for cumulative annual energy savings in the Commission's Rule 4 CSR 240-20.094(2).





Staff is conducting its review of GMO's triennial compliance filing and will file its report not later than September 5, 2012.

Staff Expert/Witness: John A. Rogers

B. Demand-Side Management Program Prudence

1. <u>Rate-Making Treatment for the DSM Program Cost</u>

GMO's DSM Account 182-440 contains costs that have been incurred for thirteen (13) DSM programs[96] along with: (1) costs not directly assignable to any individual program, and (2) DSM market research costs. At this time, Staff has no recommended disallowances to the costs charged to GMO's DSM Account 182-440.

As approved in the stipulation and agreements and ordered by the Commission in Case Nos. ER-2007-0004[97] and EO-2007-0298 [98], the GMO Advisory Group provides suggestions and advice to the Company on DSM program selection and other issues including the funding goal of one percent of annual revenues[99] to implement cost-effective energy efficiency programs by

[96] DSM programs consist of two (2) demand response, nine (9) energy efficiency and two (2) affordability programs, including the low income weatherization program.
[97] Case No. ER-2007-0004, Exhibit A, *Stipulation And Agreement As To Certain Issues*, p. 7.
[98] Case No. EO-2007-0298, *Non-Unanimous Stipulation and Agreement*, p. 26.
[99] In 2011, GMO spent approximately $4.85M on its DSM programs of the approximately $169M in operating revenues.

2010. Further, in Case No. ER-2010-0356, the parties agreed to, and the Commission ordered "… that the advisory groups…shall continue through the "bridge" period until replaced by the implementation of the MEEIA rules or other Commission order[100]." The KCPL and GMO DSM Advisory Groups hold joint meetings. Based on Staff's participation in the GMO Advisory Group meetings and Staff's review of the costs in Account 182-440, Staff has identified no evidence of imprudence regarding the costs charged to the DSM programs.

Staff Expert/Witness: Hojong Kang

C. High Efficiency Street and Area Lighting

Staff recommends that GMO complete the evaluations of its pilot projects' of Light Emitting Diode (LED) Street and Area Lighting ("SAL") systems, and no later than the end of calendar year 2012, file either a compliance LED lighting tariff, or a status report as to when it anticipates filing such tariff. As part of the settlement of certain issues in Case No. ER-2010-0356, GMO agreed during the February 4, 2011 hearing on the record to "…file by the end of calendar year 2012 either a LED lighting tariff, or when [GMO] anticipate[s] filing such LED lighting tariff. Also by the end of calendar year 2012, GMO shall file the results of its LED study, which shall include a review of potential LED lighting health issues.[101]" Staff is not recommending that GMO offer a LED SAL demand-side program unless GMO's analysis shows that a LED SAL demand-side program would be cost-effective. However, if a LED SAL demand-side program is not cost-effective, the Staff recommends that the Commission require GMO to provide its workpapers and analysis to Staff. Staff further recommends that GMO file a proposed tariff sheet(s) that would provide LED SAL services at cost plus the return authorized by the Commission to its customers.

1. Current Street Lighting for KCPL Missouri

Currently, GMO has approximately 458 public street and highway lighting customers in its service territory, using a total of approximately 42,680 MWh annually according to its 2011 Annual Report. Virtually all of the existing installed lighting fixtures in GMO's service area are

[100] Case No. ER-2010-0356, *Report and Order*, p. 118.
[101] Tr. 34, p. 3715, ll. 24-25; p. 3716, ll. 1-11.

high pressure sodium (HPS) lamps, which were determined to be the most efficient and cost-effective available technology for the SAL systems at the time they were installed.

2. GMO's LED SAL Pilot Projects

GMO's primary focus for its evaluation of alternative street and area lighting is the LED lighting system, one of the most energy efficient SAL fixtures available today. Although more expensive, LEDs offer the following advantages over traditional high-intensity discharge (HID) lamps and HPS lamps: improved energy efficiency, longer lamp life, higher quality color rendition, lower maintenance costs, and reduced light pollution. GMO is involved in the following pilot projects to evaluate cost-effectiveness, system compatibility, technology performance and efficacy of LED lighting for its service territory: GMO Municipal Lighting Service Light Emitting Diode (LED) Pilot Program; KCPL and GMO LED Pilot.

GMO Municipal Lighting Service Light Emitting Diode (LED) Pilot Program [102]. This pilot program is only offered to communities in GMO's service territory that are members of the Mid-America Regional Council (MARC) and have agreed to participate in the program. The participating communities are Harrisonville, Kearney, Lawson, Liberty, Oak Grove, Peculiar, Platte City, Pleasant Hill, Raymore, Raytown, and Smithville. MARC received an American Recovery and Reinvestment Act of 2009 grant totaling approximately $4,000,000 from the Department of Energy (DOE) to deploy, evaluate costs, and identify street light technologies for adoption of high efficiency street lights. During the course of this pilot program, GMO is working with MARC, participating communities, and joint partners KCPL, Westar Energy, Inc., and Platte-Clay Electric Cooperative to review and evaluate the costs and benefits of the LED SAL systems. If the technologies are suitable, new tariffs will be established by the Company to guide further deployment. A final evaluation report for this pilot program is not expected until late 2013.

KCPL and GMO LED Pilot. Through data request responses from GMO,[103] Staff has learned that KCPL and GMO are conducting a LED pilot program with five (5) area communities – Blue Springs, Gladstone, Liberty, and St. Joseph in Missouri and Prairie Village in Kansas – where 44 LED fixtures were installed representing products of six (6) selected

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[102] KCP&L Greater Missouri Operations Company, P.S.C. MO. No. 1, Sheet Nos. 134, 135 and 136.

[103] Based on the Data Request No. 0203 for Case No. ER-2012-0175.

vendors. Local communities are interested in learning more about LED lighting and have received pressure from residents to install energy efficient lighting that lowers cost and reduces effects on the environment. The final field report for this LED program evaluation is expected by August 30, 2012[104].

3. <u>KCPL's LED SAL Pilot Projects</u>

Because GMO is KCPL's affiliate, the results from the following KCPL LED SAL pilot projects will likely provide valuable information for GMO's decisions concerning its future LED SAL services.

<u>Electric Power Research Instit ute (EPRI) LED SAL P roject</u>. As a host utility in ERPI's LED SAL collaboration project, KCPL has replaced twelve (12) of its HID lighting systems with LED lighting systems and will document on a quarterly basis its evaluation of the cost-effectiveness, system compatibility, technology performance and efficacy of the LED lighting for its service territory. KCPL anticipated completion of the final report for this project in July 2012.

<u>LED Inrmation Sharing with City of Kansas City.</u> The City of Kansas City, Missouri ("KCMO") has installed 120 LED fixtures for testing and field measurement of lighting effectiveness. KCPL and KCMO have agreed to share the data and results of their respective LED pilot programs. Staff will review the KCMO final report when it becomes available.

Staff will continue to view the GMO LED SAL systems pilot projects' evaluation reports as they become available and will update its review and recommendations when appropriate to do so.

Staff Expert/Witness: Hojong Kang

D. Tariff Issues

Staff recommends the following changes to GMO's tariff:

- Municipal Street Lighting Service – LED Pilot GMO tariff sheet No. 134 should include a reference to Peculiar, Missouri in its tariff. Peculiar, Missouri was erroneously included in KCPL's tariff, but should be included in GMO's tariff. I proposed the reference deletion of Peculiar, Missouri in KCPL's tariff in its current rate case, ER-2012-0174, and the insertion of Peculiar in GMO's tariff.

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[104] Based on the Data Request No. 0203.2 for Case No. ER-2012-0175.

- On Tariff Sheet No. 29, LARGE GENERAL SERVICE ELECTRIC, the tariff language heading reads BASE RATE, MO938, MO939, MO940, Staff recommends that it be changed to BASE RATE, MO938 (Primary), MO939 (Substation), MO940 (Secondary). The additional tariff language provides a more descriptive definition of the customer class rate code.

- On Tariff Sheet No. 31, LARGE POWER SERVICE ELECTRIC, the tariff language heading reads BASE RATE, MO944, MO945, MO946, MO947. Staff recommends that it be changed to BASE RATE, MO944 (Secondary), MO945 (Primary), MO946 (Substation), MO947 (Transmission). The additional tariff language provides a more descriptive definition of the customer class rate code.

- On Tariff Sheet No. 34, PRIMARY DISCOUNT RIDER ELECTRIC, under the AVAILABILITY section, the tariff language should read "Available to customers served under Large General Service or Large Power rate schedules who receive three-phase alternating-current electric service at a primary voltage level or above, and who provide and maintain all necessary transformation and distribution equipment beyond the point of Company metering". This would replace the current tariff language, "Available to customers served under rate schedules MO940 or MO944 who receive three-phase alternating-current electric service at a primary voltage level and who provide and maintain all necessary transformation and distribution equipment beyond the point of Company metering". The additional tariff language provides a more descriptive definition of the affected eligible customers.

Staff Expert/Witness: Thomas M. Imhoff

E. KCPL Smart Grid Update

This section provides information on the history and status of GMO's Smart Grid deployment and does not address any particular revenue requirements in this rate case. GMO is requesting funding for a new group of employees dedicated to operating, maintaining and repairing the Smart Grid electrical infrastructure components as described in the testimony of GMO witness William P. Herdegen, III.[105] Staff is not aware of any advanced metering infrastructure (AMI) applications in the GMO service territory. GMO has been investing in Distribution Automation and Smart Grid technologies since 2009 that include 2-way wireless communication to field devices, capacitor automation, 34kV recloser automation, voltage and faulted circuit monitors and automate 15kV switching devices.[106] Although not as visible to the public as KCPL's Smart Grid demonstration project, the Smart Grid electrical grid infrastructure

[105] Direct Testimony of GMO witness William P. Herdegen, III, page 2, lines 10-22 and pages 3-5.
[106] Direct Testimony of GMO witness William P. Herdegen, III, page 2, lines 15-22 and page 3 lines 1-2.

components currently in operation are planned to match those same components on KCPL's system and include the following:[107]

- Capacitor banks that control or stabilize the system voltage by minimizing voltage drops and absorbing energy from a line spike. The banks provide voltage stability by switching in capacitor banks to provide reactive power when large inductive loads occur, such as when air conditioners, furnaces, dryers, and/or industrial equipment start;
- S&C Electric Company SCADAmate® Switching Systems[108] for pole mounted overhead line circuits;
- S&C Electric Company IntelliRupter Pulsecloser® reclosers[109] for electrical fault interruption, isolation and circuit restoration. These intelligent reclosers confirm that there is not a fault on the circuit prior to reclosing;
- S&C Electric Company Vista Gear®[110] that feature circuit load interrupter switches and resettable fault interrupters for pad mounted, vault and subsurface applications.;
- Communicating or Automated Faulted Circuit Indicators (FCIs). These devices provide information on electrical line disturbances and communicate this information to system operators in near real time;
- Intelligent Electronic Device (IED) Radios and Communications;
- AMI or AMR Communications Equipment; and
- Meter Communications to other (non-AMI) Devices (Zigbee, etc).

Staff Expert/Witness: Randy Gross

F. Renewable Energy Standard

1. <u>Background Information</u>

The Missouri Renewable Energy Standard Law ("RES Law")[111] was enacted as a voter initiative petition in November 2008. Provisions of the resulting statute and regulations require

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[107] Direct Testimony of GMO witness William P. Herdegen, III, page 6, lines 2-20.
[108] http://www.sandc.com/products/switching-overhead-distribution/scada-mate-cx.asp
[109] http://www.sandc.com/products/switching-overhead-distribution/intellirupter-pulsecloser.asp
[110] http://www.sandc.com/products/underground-distribution-switchgear/vista.asp

GMO and the other investor-owned utilities to meet certain requirements regarding the use of renewable energy. Beginning January 1, 2010, the RES Law requires GMO to provide a rebate ($2.00 per installed watt)[112] to its retail customers for installation of solar electric systems on their premises.[113] Utilization of a Standard Offer Contract ("SOC") for the purchase of Solar Renewable Energy Certificates ("S-RECs") from customer-owned solar electric systems is optional for the utility companies.[114] GMO has not filed SOC tariffs at this time.

GMO filed an application for an Accounting Authority Order ("AAO") associated with RES Law compliance costs.[115] That application was resolved through a Non-unanimous Stipulation and Agreement and approved by the Commission on April 30, 2012. The AAO authorized GMO to: (a) record all incremental operating expenses associated with the cost of solar rebates, the cost to purchase renewable energy credits ("RECs"), the cost of standard offer contracts and other related costs incurred as a result of compliance with the RES Law; (b) include carrying costs based on the Company's short term debt rate on the balances; and (c) defer such amounts in a separate regulatory asset with the disposition to be determined in GMO's next general rate case.

For calendar years 2011 through 2013, the RES Law requires GMO to generate or purchase two percent (2%) of its retail sales using renewable energy resources.[116] For each portfolio requirement, GMO must derive two percent (2%) of the requirement from solar energy.[117] Renewable Energy Certificates ("RECs") can be banked for three (3) years and utilized for future compliance purposes.[118] GMO filed the required RES Law Compliance Plans (calendar years 2011 and 2012) and RES Law Compliance Report (calendar year 2011)[119]. Each RES Law Compliance Plan provides information regarding the utility's plan for the current calendar year and the subsequent two (2) calendar years. The RES Law Compliance Report is a status report on the utility's compliance for the preceding calendar year. For the 2011 calendar

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[111] Mo. Rev. Stat. § 393.1020 (2010).
[112] Mo. Rev. Stat. § 393.1030.3 (2010).
[113] The rebate provision has a specific limitation on the size of the system, namely no larger than 25 kilowatts per system.
[114] 4 CSR 240-20.100 (4)(H)1.
[115] Case No. EU-2012-0131, this Case also included KCPL.
[116] Mo. Rev. Stat. § 393.1030 .1(1) (2010).
[117] Mo. Rev. Stat. § 393.1030.1 (2010).
[118] "An unused credit may exist for up to three years from the date of its creation." Mo. Rev. Stat. § 393.1030.2 (2010).
[119] GMO filed its RES Plan for calendar years 2011-2013 in Case No. EO-2011-0278, its RES Plan for calendar years 2012-2014 and RES Report for calendar year 2011 in EO-2012-0349.

year, GMO utilized renewable energy and RECs acquired through a purchased power agreement from Gray County Wind Energy for the non-solar requirement and S-RECs from third-party brokers for the solar requirement.[120]

GMO will utilize its existing renewable resources, purchased power agreements ("PPA") from renewable resources, and purchased RECs for RES Law compliance. In addition to the expenses associated with the items in the previous sentence and solar rebates, there are expenses associated with the Commission-designated REC tracking system[121]. These expenses include registration, subscription, and volumetric fees. Because of the statutory three (3) year REC expiration and the current RES Law requirements, GMO may have an excess of RECs. These excess RECs should be sold (if possible), otherwise the RECs will expire.

The Staff continues to monitor File No. EO-2012-0349 concerning GMO RES Law Compliance Report for calendar year 2011, and its RES Law Compliance Plan for calendar years 2012-2014. GMO's 2012 RES Law Compliance Plan and 2011 RES Law Compliance Report case is currently pending and Staff may have additional testimony in rebuttal or surrebuttal based on any decision made by the Commission.

Staff Expert/Witness: Michael E. Taylor

2. **Renewable Energy Costs**

Pursuant to 4 CSR 240-20.100 (6)(D), the RES rule provides a recovery option for compliance costs. The rule provides that GMO may:

> …recover RES compliance costs without the use of a RESRAM through rates established in a general rate proceeding. In the interval between general rate proceedings, the electric utility may defer the costs in a regulatory asset account and monthly calculate a carrying charge on the balance in that regulatory asset account equal to its short-term cost of borrowing. All questions pertaining to rate recovery of the RES compliance costs in a subsequent general rate proceeding will be reserved to that proceeding, including the prudence of the costs for which rate recovery is sought and the period of time over which any costs allowed rate recovery will be amortized.

On April 19, 2012, the Commission authorized GMO's use of an accounting authority order in Case No. EU-2012-0131, to

[120] EO-2012-0349, *Renewable Energy Standard Compliance Report*, page 4.
[121] North American Renewables Registry.

> (a) record all incremental operating expenses associated with the cost of solar rebates, the cost to purchase renewable energy credits, the cost of the standard offer and other related costs incurred as a result of compliance with Missouri's Renewable Energy Standard Law in USOA Account 182; (b) include carrying costs based on the Compan[y's] short term debt rate on the balances in those regulatory assets; and (c) defer such amounts in a separate regulatory asset with the disposition to be determined in the Compan[y's] next general rate cases.[122]

Discussions continue with the Company concerning the level of RES costs through March 31, 2012. Staff recommends reflecting in the cost of service an annualized level of RES expenditures over the twelve month period ending March 31, 2012, to be included in rates for both MPS and L&P. The adjustment is reflected in Staff's Accounting Schedule 9 for MPS is E-125.4 and for L&P is E-133.4. In addition, Staff has included a three (3)-year amortization of deferred RES costs for both MPS and L&P. The adjustment is reflected in Staff's Accounting Schedule 9 for MPS is E-125.5 and for L&P is E-133.5. As part of its true-up audit, Staff will continue to examine RES costs through August 31, 2012, and any Commission decision in File No EO-2012-0348, and make additional adjustments as needed to the level for inclusion in permanent rates.

Staff Expert/Witness: Karen Lyons

G. Energy Independence and Security Act of 2007 (EISA)

On December 19, 2007, the Energy Independence and Security Act of 2007 ("EISA"), which amended various sections of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), was signed into law. PURPA's purposes are to encourage: 1) conservation of electric energy, 2) efficiency in the use of facilities and resources by electric utilities, and 3) equitable rates to consumers of electricity.[123] EISA established four additional PURPA standards for electric utilities as follows: Integrated Resource Planning (IRP), Rate Design Modifications to Promote Energy Efficiency Investments, Consideration of Smart Grid Investments, and Smart Grid Information.

On December 15, 2008, Staff filed requests for the Commission to open dockets for the purpose of establishing records for consideration and determination as to whether it is

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[122] File No. EU-2012-0131, *Order Approving And Incorporating Stipulation And Agreement*, p. 2.
[123] PURPA Section 101.

appropriate to implement the new standards encompassed within EISA to carry out the above noted purposes. EISA establishes timeframes within which the Commission is to perform this consideration and determination. The Commission should begin consideration within one year after enactment of the standard (i.e., by December 19, 2008) and complete its consideration and determination no later than two years after enactment (i.e., by December 19, 2009). Absent such determination, the Commission should consider in a general rate case for each individual electric utility whether or not it is appropriate to implement such standard to carry out the above noted purposes. Should the Commission decline to implement a PURPA standard for which it determines the standard is appropriate to carry out the above-noted purposes, the Commission is directed to state in writing its reasons.

In response to Staff's request, the Commission opened the following dockets in accordance with the mis-numbering of the four new standards as had occurred in the original EISA legislation:

1) Case No. EW-2009-0290: In the Matter of the Consideration of Adoption of PURPA **Section 111(d)(16)** Smart Grid Investments Standard as Required by Section 532 of the Energy Independence and Security Act of 2007. ("Smart Grid Investment Docket")

18. 2) File No. EW-2009-0291: In the Matter of the Consideration of Adoption of the PURPA **Section 111(d)(16)** Integrated Resource Planning Standard as Required by Section 532 of the Energy Independence and Security Act of 2007. ("IRP – Docket")

19. 3) File No. EW-2009-0292: In the Matter of the Consideration of Adoption of the PURPA **Section 111(d)(17)** Rate Design Modifications to Promote Energy Efficiency Investments Standard as Required by Section 532 of the Energy Independence and Security Act of 2007. ("Rate Design Docket")

20. 4) Case No. EW-2009-0293: In the Matter of the Consideration of Adoption of PURPA **Section 111(d)(17)** Smart Grid Information Standard as Required by Section 1307 of the Energy Independence and Security Act of 2007. ("Smart Grid Information Docket").

Staff understands that Congress corrected the mis-numbering of the four new EISA standards in Section 408, Technical Corrections, as enacted as part of the American Recovery and Reinvestment Act of 2009.[124] By May 6, 2009, the Commission issued orders correcting the numbering of the four new PURPA standards and re-numbered and consolidated the workshop dockets as follows:

1) File No. EW-2009-0290: In the Matter of the Consideration of Adoption of the PURPA **Section 111(d)(16)** Integrated Resource Planning Standard as Required by Section 532 of the Energy Independence and Security Act of 2007. ("IRP Docket");

2) File No. EW-2009-0291: In the Matter of the Consideration of Adoption of the PURPA **Section 111(d)(17)** Rate Design Modifications to Promote Energy Efficiency Investments Standard as Required by Section 532 of the Energy Independence and Security Act of 2007. ("Rate Design Docket");

3) File No. EW-2009-0292: In the Matter of the Consideration of Adoption of PURPA **Section 111(d)(18)**, Smart Grid Investments Standard, and PURPA **Section 111(d)(19),** Smart Grid Information Standard as Required by Section 1307 of the Energy Independence and Security Act of 2007. ("Smart Grid Docket").

On November 23, 2009, the Commission issued its *Order Finding Consideration / Implementation Of New Federal Standards Through Workshop And Rulemaking Procedures Is Required* in File Nos. EW-2009-0290, EW-2009-0291, and EW-2009-0292. The Commission stated in its order at page 5, "The Commission has satisfied the requirements for consideration of the new EISA standards, and on the basis of the quasi-legislative record created in these workshops, the Commission determines that no comparable standards have been considered that would constitute prior state action and prohibit the Commission from taking any further action in relation to the new EISA standards."

Since there has been no specific determination to date by the Commission, Staff recommends the Commission consider each standard and make its determination with respect to GMO in this rate case based on the following discussion.

[124] Pub. L. No. 110-140, 121 Stat. 1492 (2007), amended by Section 408 of The American Recovery and Reinvestment Act of 2009 (the EISA, prior to this amendment, is codified at 16 USCS 2621 and 2622 (Cum. Supp. 2008)). PURPA is codified generally in 16 USCS 2601 et seq., but various provisions appear elsewhere in the United States Code.

IRP Docket

PURPA Section 111(d)(16), Integrated Resource Planning Standard as required by Section 532 of the Energy Independence and Security Act of 2007, requires state commission consideration of whether to implement the following:

21. (A) integrate energy efficiency resources into utility, State, and regional plans; and

22. (B) adopt policies establishing cost-effective energy efficiency as a priority resource.

Staff held several workshops, which culminated in the Commission's promulgation of a rulemaking in File No. EX-2010-0254, In the Matter of a Proposed Rulemaking Regarding Revision of the Commission's Chapter 22 Electric Utility Resource Planning Rules. The revised Chapter 22 rules became effective on June 30, 2011, which require the screening and integration of cost-effective energy efficiency resources to be included in the electric utility resource planning process. After opportunity for input from the public which included comments being submitted by the electric utilities, Office of the Public Counsel, Missouri Department of Natural Resources, Renew Missouri, Great Rivers Environmental Law Center, and Dogwood Energy, LLC, the Commission approved the policy in Chapter 22 of requiring demand-side resources be evaluated on an equivalent basis with supply-side resources subject to compliance with all legal mandates.[125]

In addition, the Commission has a workshop docket, Case No. EW-2010-0187, opened to investigate how to achieve its statutory responsibilities under the Missouri Energy Efficiency Investment Act ("MEEIA"), Section 393.1075, RSMo., within the background of Federal Energy Regulatory Commission ("FERC") policies that eliminate barriers to demand response and that direct the Midwest Independent Transmission System Operator ("MISO") and the Southwest Power Pool ("SPP") to accommodate state policy regarding retail customer demand-side activity. This docket was opened to explore the best model or models to achieve the requirements of the MEEIA through state demand-side programs, wholesale market opportunities available in MISO or SPP, or possible hybrid approaches, and the implications for resource planning under various approaches. The roles for utilities, aggregators of retail consumers ("ARCs"), customers in all

[125] 4 CSR 240-22.010(2)(A)

classes, and other stakeholders in designing the appropriate means of achieving Missouri's policy objectives, and for interacting with MISO and SPP are also to be evaluated.

While not specifically making a determination to implement PURPA Section 111(d)(16), the Commission has promulgated rulemakings to address the principles of that section; therefore, Staff suggests there is nothing that remains for the Commission to determine in response to PURPA Section 111(d)(16), and recommends the Commission make such a finding in this rate case.

Rate Design Docket

PURPA Section 111(d)(17), Rate Design Modifications to Promote Energy Efficiency Investments Standard as required by Section 532 of the Energy Independence and Security Act of 2007, requires state commissions to consider whether to implement: 1) removing the throughput incentive and disincentives to energy efficiency; 2) providing utility incentives for successful management of energy efficiency programs; 3) including the impact of energy efficiency as one of the goals of retail rate design; 4) adopting rate designs that encourage energy efficiency; 5) allowing timely recovery of energy efficiency related costs; and 6) offering energy audits, demand-response programs, publicizing the benefits of home energy efficiency improvements and educating homeowners about Federal and State incentives. Similarly, in 2009, Governor Jeremiah "Jay" Nixon signed Senate Bill 376, the "Missouri Energy Efficiency Investment Act," with a stated policy to "value demand-side investments equal to traditional investments in supply and delivery infrastructure and allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs." Section 393.1075.3

The Commission held several workshops, which culminated in the promulgation of a rulemaking in File No. EX-2010-0368, In the Matter of the Consideration and Implementation of Section 393.1075, The Missouri Energy Efficiency Investment Act ("MEEIA"). The rules became effective on May 30, 2011 – Rules 4 CSR 240-20.093, 20.094, 3.163, and 3.164. GMO submitted its MEEIA application on December 22, 2011, in Case No. EO-2012-0009. The parties continue to negotiate issues related to the filing, and GMO has extended the effective date of the MEEIA tariff filings until September 17, 2012. Despite the outcome of the case, the Commission has in place the framework necessary for the Commission to make a determination on the associated PURPA principles as outlined above.

SB 376 contains a provision which states, "Prior to approving a rate design modification associated with demand-side cost recovery, the commission shall conclude a docket studying the effects thereof and promulgate an appropriate rule." Section 393.1075.5. The Commission held additional workshops on this provision of SB 376, and on March 20, 2012, Electric Utility Consultants, Inc. ("EUCI"), provided to the Commission, Staff and interested stakeholders, an in-house, specialized training course on Electric Rate Design Modifications Associated with Demand-Side Cost Recovery.

The revised Chapter 22 rules incorporate requirements for rate design analysis. For instance, 4 CSR 240-22.030(5)(C) requires, at a minimum, that load forecast models assess the impact of legal mandates, economic policies, and rate designs on future energy and demand requirements. Likewise, 4 CSR 240-22.050(4)(B) requires the utility to describe and document its demand-side rate planning and design process, and when appropriate, to consider multiple demand-side rate designs for the major classes.

The Commission sets rates in Missouri based on the cost to serve the customer. This gives the customer accurate cost information on which it can determine whether or not it wants to implement energy efficiency measures. Increasing rates to encourage energy efficiency or setting rates lower for customers that implement energy efficiency sends inaccurate costs signals to the customers. Therefore, without getting into a discussion of general ratemaking principles, but for purposes of the Commission's consideration as to whether it should implement PURPA Section 111(d)(17), setting rates based on cost to serve the customer sends the appropriate price signal to the customer to make decisions on energy efficiency. The Commission's revised Chapter 22 rules require the electric utilities to look at all forms of incentivizing energy efficiency including home energy audits and demand-response programs.

As a result of these activities, Staff recommends that the Commission, in this case, make a determination that, although additional activities related to SB 376 are contemplated, no further determination is needed in response to PURPA Section 111(d)(17) for GMO.

Smart Grid Docket

In response to **PURPA Section 111(d)(18)**, Smart Grid Investments Standard, and **PURPA Section 111(d)(19),** Smart Grid Information Standard, as required by Section 1307 of the Energy Independence and Security Act of 2007, the Commission, on December 29, 2010, issued an order to open File No. EW-2011-0175 as a repository for information concerning the Smart Grid in Missouri.

On January 13, 2011, Staff filed the *Missouri Smart Grid Report* ("Report") in File No. EW-2011-0175. The Report discusses Smart Grid technologies, provides a status update on various Smart Grid opportunities in Missouri and presents issues and concerns related to Smart Grid deployment. It identifies key issues requiring further emphasis, including planning, implementation, cost recovery, cyber-security and data privacy, customer acceptance and involvement, and customer savings and benefits. The Report recommends the Commission hold a Smart Grid workshop every six months for information exchange and sharing of best practices and educational opportunities; and also recommends the Commission open a docket to address cost recovery issues.

The Commission held Smart Grid conferences on June 28, 2010, and November 29, 2011. Panelist and speaker topics included such items as updates on Smart Grid projects in Missouri, customer views, education and engagement, and challenges to deployment.

The information provided in the workshop is provided to the public through the Commission's electronic filing and information system. The Smart Grid was also the most recent subject of the *PSConnection,* a publication of the Commission which is available online, at public hearings, at the State Fair booth, and at all other opportunities where the Commission interacts with the public.

On July 17, 2012, the Commission issued its *Order Directing Notice and Directing Filing* in File No. EW-2013-0011. The Commission noted, the electric power industry is increasingly incorporating information technology (IT) systems and networks into existing infrastructure, but the increased reliance on IT systems and networks exposes the grid to cybersecurity vulnerabilities. The Commission is charged with assuring public utility companies provide safe and adequate service at just and reasonable rates. The Commission issued its Order to gather information related to cyber vulnerabilities and the integrity of the electric utilities' internal cybersecurity practices. All Missouri regulated electric utilities are required to file answers to all questions contained in the Order by August 31, 2012. This provides yet another opportunity for the Commission to explore issues and take action related to the PURPA standard.

PURPA Section 111(d)(19) requires all electricity purchasers and other interested parties to be provided access to information from their electricity provider related to time-based prices, usage, and sources of power provided by the utility and type of generation, with associated greenhouse gas emissions for each type of generation, to the extent such information is available, on a cost-effective basis. While the Commission has not specifically addressed these issues in the context of PURPA Section 111(d)(19), there have been several forums in which stakeholders have discussed related issues and Staff recommends these issues continue to be addressed as they arise.

Staff recommends the Commission make a determination in this case that it has established the appropriate avenues for monitoring Smart Grid activities and no greater ongoing activity is needed in response to PURPA Section 111(d)(18) and PURPA Section 111(d)(19) in the context of GMO.

Staff Expert/Witness: Natelle Dietrich

H. Capacity Planning

Recommendation

Staff recommends that the Commission not allow GMO and KCPL to conduct joint resource planning of capacity and resources. If the Commission considers allowing joint resource planning, ***before*** the Commission allows KCPL and GMO to share capacity resources or engage in capacity resource planning together, it should require: 1) GMO and KCPL to file a detailed proposal for allocating capacity and energy between KCPL and GMO, and if GMO's MPS and L&P rate districts are not eliminated, between GMO's MPS and L&P rate districts; and 2) KCPL and GMO to file a definitive plan for merging KCPL and GMO into one electrical corporation.

Background

Regardless of how the issue of assigning GMO's capacity to MPS and L&P for developing rates for these districts is resolved, it will not resolve Staff's concern with how GMO's future capacity needs will be met. **

NP

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On a stand-alone basis, **

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One resolution for GMO's capacity shortfall, as pointed out in GMO witness Tim M. Rush's direct testimony, is the combination of the resources of KCPL and GMO, since GMO needs capacity and KCPL has excess capacity. Staff sees some benefits of combining the two for sharing capacity and capacity planning. However, the benefits of such an arrangement would not match the benefits of the current allocation of resources between MPS and L&P rate districts where energy is transferred at cost.

This type of consolidation of capacity and capacity resource planning impacts much more than short-run capacity needs, just like a decision regarding the assignment of capacity between L&P and MPS or the elimination of L&P and MPS rate districts impacts more than just meeting GMO's capacity requirements. In the long-run, when additional capacity is needed for KCPL and GMO, the problems that have been described above for allocating costs between MPS and L&P will also exist for allocating capacity between KCPL and GMO. GMO and KCPL have neither developed nor proposed any processes for allocating energy and capacity between KCPL and GMO and then between the MPS and L&P rate districts. ***Before*** the Commission allows KCPL and GMO to share capacity resources or engage in resource planning as one company, it should require GMO and KCPL to file: 1) a detailed process for the allocation of capacity and energy between KCPL and GMO and, if they are not eliminated, between GMO's MPS and L&P rate districts: and 2) a definitive plan for the merger of the two companies.

An alternative available to KCPL and GMO may involve KCPL and GMO entering into a long-term contract for KCPL to supply capacity and energy to GMO after GMO issues a Request for Proposals ("RFP") for a long term PPA and evaluates the responses it receives. If KCPL's bid would be the low cost solution, a contract between KCPL and GMO would have to meet the requirements of 4 CSR 240-20.015 Affiliate Transaction rule.

KCPL and GMO filed reports regarding their resource planning processes in Case Nos. EO-2012-0323 and EO-2012-0324, respectively, on April 9, 2012. The Staff and other parties' reports regarding compliance and concerns with these resource plan filings will be made September 6, 2012. The Commission should not make any determinations regarding the acknowledgment of a resource planning process in this rate case. The resource planning cases are the correct cases for the Commission to make such determinations.

Staff Expert/Witness: Lena M. Mantle

XV. Transition Cost Recovery Mechanism

A. Acquisition Transition Cost Recovery

On April 4, 2007, Great Plains, KCPL and Aquila filed an application with the Commission seeking authority for a series of transactions whereby Aquila would become a direct, wholly-owned subsidiary of Great Plains. On July 1, 2008, in Case No. EM-2007-0374 ("Acquisition Case"), the Commission granted that authority. On July 14, 2008 Great Plains completed the acquisition.

In Commission's Report and Order for the Acquisition Case, at page 282, in ordered paragraph 6(C), the Commission included the following condition:

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

The Commission found that there was potential for significant savings as a result of the acquisition, and was supportive of Great Plains, KCPL and Aquila recovering the costs they incurred in combining the operations of KCPL and Aquila. These costs are referred to as "transition costs" and include non-executive severance costs for employees terminated as a result of the acquisition, facilities' integration costs, and incremental third-party and other non-labor expenses incurred to support the integration of the operations of KCPL and Aquila.

The Commission also addressed costs referred to as transaction costs—costs to complete the acquisition such as investment banking fees, legal costs preparing legal documents to complete the acquisition. In the section of its Report and Order where it presented its "Final Conclusions Regarding Transaction and Transition Cost Recovery," on page 241, the Commission stated:

> Substantial and competent evidence in the record as a whole supports the conclusions that: (1) the Applicants' calculation of transaction and transition costs are accurate and reasonable; (2) in this instance, establishing a mechanism to allow recovery of the transaction costs of the merger would have the same effect of artificially inflating rate base in the same way as allowing recovery of an acquisition premium; and (3) the uncontested recovery of transition costs is appropriate and justified. The Commission further concludes that it is not a detriment to the public interest to deny recovery of the transaction costs associated with the merger and not a detriment to the public interest to allow recovery of transition costs of the merger.
>
> If the Commission determines that it will approve the merger when it performs its balancing test …, the Commission will authorize KCPL and Aquila to defer transition costs to be amortized over five years. (Footnote omitted.)

In the footnote omitted above (footnote 930), the Commission stated:

> The Commission will give consideration to their [transition costs] recovery in future rate cases making an evaluation as to their reasonableness and prudence. At that time, the Commission will expect that KCPL and Aquila demonstrate that the synergy savings exceed the level of the amortized transition costs included in the test year cost of service expenses in future rate cases.

In GMO's 2010 Rate Case the Commission determined the appropriate amount of acquisition transition costs to include in GMO's rates. The Commission ordered recovery of the transition costs over five years beginning with the effective date of rates in GMO's 2010 Rate Case. KCPL and GMO have not deferred any additional transition costs after December 31, 2010. Below are the total unamortized transition costs, the total direct rate recovery at

January 31, 2013, and the balance at January 31, 2013. The projected effective date of rates in the current 2012 Rate Cases is January 27, 2013.

Total Acquisition Transition Costs at January 31, 2013	
	January 31, 2013
KCPL - MO	
Total Unamortized Transition Costs	$ 19,344,018
Total Direct Rate Recovery	6,770,406
Balance At Date	12,573,611
GMO - MPS	
Total Unamortized Transition Costs	17,727,367
Total Direct Rate Recovery	5,672,758
Balance At Date	12,054,610
GMO - L&P	
Total Unamortized Transition Costs	4,452,471
Total Direct Rate Recovery	1,424,791
Balance At Date	3,027,680
Summary All Jurisdictions	
Total Unamortized Transition Costs	41,523,856
Total Direct Rate Recovery	13,867,954
Balance At Date	27,655,902

Directly through the cost of service through rates, KCPL and GMO will recover $13.8 million in transition costs through the effective date of rates in this case. The total unamortized balance for all jurisdictions is $27.6 million at January 2013 (see above table).

As part of its *Report and Order* in the Findings of Fact concerning this issue in GMO's 2010 Rate Case, the Commission found the following:

> 461. In Missouri, it is well established that there is a lag between when a cost or revenue is incurred and when that cost or revenue is reflected in rates. This is known as regulatory lag. [footnote omitted]
>
> 462. As a result of regulatory lag, if a utility experiences a cost decrease, there is a lag in time until that reduced cost is reflected in rates. During that lag, the Company shareholders reap, in the form of increased earnings, the entirety of the benefit associated with reduced costs. The Company shareholders also reap, in the form of decreased earnings, the entirety of the loss associated with increased costs.

The Commission restated in its GMO 2010 Case Order Findings of Fact what it had stated in its Acquisition Case Order concerning recovery of transition costs:

> 464. The Commission qualified its authorization by stating that, "The Commission will give consideration to …[the transition costs] recovery in future rate cases making an evaluation as to their reasonableness and prudence. At that time, the Commission will expect that KCP&L and Aquila demonstrate that the synergy savings exceed the level of the amortized transition costs included in the test year cost of service expenses in future rate cases." [footnote omitted] The Commission contemplated that the recovery would only happen if the synergy savings were greater than the costs to achieve those savings. [footnote omitted]

The Commission, in both the Acquisition Order, and in its GMO 2010 Case Order, relied upon the Synergy Tracking Model that in the Acquisition Case it ordered be used as shown in the finding in its 2010 Case Order that follows:

> 469. The Companies developed and maintained a Synergy Tracking Model which demonstrated that the merger synergy savings for non-fuel operations and maintenance expense exceed the amortization of merger transition costs. [footnote omitted]

In the same Order, the Commission noted Staff's analysis of the Commission-ordered Synergy Savings Tracking Model:

> 471. Staff performed an analysis of both the Commission ordered synergy savings tracking model and KCP&L created synergy project charter database. Staff's analysis showed that the amount of synergies in the synergy project database exceeded those in the Commission-ordered tracking system. [footnote omitted]

When reading Findings of Fact 464, 469, and 471 above in GMO's 2010 Case Order, the Commission relied upon, in part, the results of the Commission Ordered Synergy Savings Tracking Model. However, according to its response to Data Request 195.1 in Case No. ER-2012-0174, KCPL, and therefore GMO, has not maintained the Commission Ordered Synergy Savings Tracking Model:

> KCP&L has not maintained the synergy tracking model that the Commission ordered to demonstrate that amortization of transition costs should begin. KCP&L has continued to track synergies internally using the charter database provided in the response to data request 196 in the current case (ER-2012-0174).

The relevance of an updated Commission Ordered Synergy Savings Tracking Model lies in what the model was designed to demonstrate. In Case No. ER-2010-0355, the model KCPL provided compared the adjusted base year of non-fuel operations and maintenance (non-fuel O&M) of standalone KCPL and Aquila operations in calendar year 2006 to the combined KCPL and GMO operations of calendar year 2009, the test year in the 2010 Case. The model demonstrated that the annual synergies realized amounted to $48.5 million. The Commission relied upon this model, as contemplated in its Acquisition Case Order, specifically in footnote 930, to give consideration of transition cost recovery in future rate cases. The Commission specifically relied upon the results of this model in its Findings of Fact in its GMO 2010 Case Report and Order that it made in Finding of Fact No. 475:

> 475. The synergy savings exceed the level of the amortized costs. [footnote omitted]

The above omitted footnote, No. 654, referenced three documents, the Direct Testimony of KCPL/GMO witness Darrin Ives, the Rebuttal Testimony of Staff witness Keith Majors, and the hearing transcript at page 3472. The Commission, in consideration of testimony and hearings, found in its Finding of Fact No. 475 that the Commission Ordered Synergy Savings Tracking Model demonstrated "[t]he synergy savings exceed the level of the amortized costs."

The Commission, in its Conclusions of Law No. 53 in the GMO 2010 Case Order reiterated its consideration of the Commission Ordered Synergy Savings Tracking Model as follows:

> 53. …[T]he Commission reserved consideration of recovery of the transition costs when it said:
>
> The Commission will give consideration to their [transition costs] recovery in future rate cases making an evaluation as to their reasonableness and prudence. At that time, the Commission will expect that KCP&L and Aquila demonstrate that the synergy savings exceed the level of the amortized transition costs included in the test year cost of service expenses in future rate cases. [Footnote 930 omitted]

KCPL, and therefore GMO, has not maintained the Commission Ordered Synergy Savings Tracking Model. In the 2010 KCPL and GMO Cases, the Commission relied upon, among other things, this very model in its decision to amortize the transition costs and include the annual amortization amounts in the revenue requirements of KCPL and GMO. While KCPL has maintained its Synergy Charter Tracking Database for recording cumulative synergy savings, without the Commission Ordered Synergy Savings Tracking Model, Staff cannot determine whether the annual synergy savings, from an adjusted 2006 base year compared to the Commission-ordered test year in this case ending September 30, 2011, exceed the amortized transition costs.

While KCPL has not maintained the Commission Ordered Synergy Savings Tracking Model, there is evidence that KCPL's administrative and general (A&G) expenses, a part of which are allocated to GMO, continue to increase and be the highest per average customer, per megawatt hour sold, and per dollar of electric operating revenue of all the electric utilities this Commission rate regulates. Staff's analysis used information directly from the FERC Form 1, in the form of Annual Reports to the Commission from its EFIS system and information from the Westar Energy FERC Form 1.

Staff presented an analysis of Administrative & General expenses in KCPL's 2010 Rate Case, and the Commission considered it in its Finding of Fact 478:

> 478. Staff did an analysis of the Companies' Administrative & General (A&G) expenses and other electric utilities in the region. [footnote omitted] Staff's analysis indicates that on a combined company basis, KCP&L and GMO have the highest A&G expenses per customer, per megawatt hour sold and per dollar of operating revenue. [footnote omitted]

As can be seen below, KCPL and GMO's Administrative & General expenses remain pervasively high. The tables below are the detail and summaries of Staff's analysis:

Administrative & General Expenses per Average Customer						
				Combined	Ameren Missouri	
Calendar 2011	Empire	GMO	KCPL	KCPL and GMO	MO Basis	Westar
A&G Expenses	36,912,783	70,505,022	173,703,809	244,208,831	275,200,772	94,161,548
Average Number of Customers	166,236	312,716	512,125	824,841	1,190,483	369,168
A&G Cost per Customer	$222.05	$225.46	$339.18	$296.07	$231.17	$255.06

Administrative & General Expenses per Megawatt Hour Sold						
				Combined	Ameren Missouri	
Calendar 2011	Empire	GMO	KCPL	KCPL and GMO	MO Basis	Westar
A&G Expenses	36,912,783	70,505,022	173,703,809	244,208,831	275,200,772	94,161,548
Megawatt Hours Sold	5,815,365	8,520,415	20,374,582	28,894,997	48,142,970	17,499,665
A&G Cost per Megawatt Hour Sold	$6.35	$8.27	$8.53	$8.45	$5.72	$5.38

Administrative & General Expenses per Electric Operating Revenue						
				Combined	Ameren Missouri	
Calendar 2011	Empire	GMO	KCPL	KCPL and GMO	MO Basis	Westar
A&G Expenses	36,912,783	70,505,022	173,703,809	244,208,831	275,200,772	94,161,548
Total Electric Operating Revenues	522,506,506	759,742,827	1,558,265,703	2,318,008,530	3,226,611,565	1,240,125,727
A&G Cost Per Electric Revenue Dollar	$0.0706	$0.0928	$0.1115	$0.1054	$0.0853	$0.0759

Continued on next page.

Three Year Analysis of FERC Form 1 Administrative & General Expenses							
	SUMMARY	**Empire**	**GMO**	**KCPL**	**Combined KCPL and GMO**	**Ameren Missouri Basis**	**Westar**
2009	A&G Cost per Customer	$170.09	$214.65	$278.43	$254.23	$211.03	$223.55
2010	A&G Cost per Customer	$194.16	$198.10	$298.54	$260.45	$201.85	$252.38
2011	A&G Cost per Customer	$222.05	$225.46	$339.18	$296.07	$231.17	$255.06
2009	A&G Cost per Megawatt Hour Sold	$5.28	$8.26	$7.08	$7.42	$5.11	$4.76
2010	A&G Cost per Megawatt Hour Sold	$5.46	$7.02	$7.10	$7.07	$4.98	$5.17
2011	A&G Cost per Megawatt Hour Sold	$6.35	$8.27	$8.53	$8.45	$5.72	$5.38
2009	A&G Cost Per Dollar of Electric Revenue	$0.0660	$0.1035	$0.1079	$0.1064	$0.0926	$0.0768
2010	A&G Cost Per Dollar of Electric Revenue	$0.0678	$0.0838	$0.1007	$0.0952	$0.0793	$0.0772
2011	A&G Cost Per Dollar of Electric Revenue	$0.0706	$0.0928	$0.1115	$0.1054	$0.0853	$0.0759

In comparison to Empire, Ameren Missouri, and Westar Energy, KCPL and GMO combined have the highest A&G cost per customer, per megawatt hour sold, and per dollar of electric revenue.

Although KCPL has not maintained the Commission Ordered Synergy Savings Tracking Model, it has maintained its Synergy Project Charter Tracking database. This database has been created by KCPL to internally track the cumulative savings it considers are a result of the acquisition of Aquila. The recorded results as of March 31, 2012 are in the table below:

Synergy Project Charter Tracking Database Synergy Savings		
Period	**Regulated Savings**	**Corporate Savings**
Q3 2008	$7,049,467	$17,927,511
Q4 2008	13,565,146	31,022,978
2008 Total	**20,614,612**	**48,950,489**
Q1 2009	11,267,258	19,189,044
Q2 2009	14,296,977	19,062,379
Q3 2009	19,711,085	19,427,888
Q4 2009	19,286,671	20,322,463
2009 Total	**64,561,991**	**78,001,774**
Q1 2010	15,875,340	20,518,886
Q2 2010	19,753,175	20,570,612
Q3 2010	27,383,306	20,479,083
Q4 2010	20,012,168	20,110,478
2010 Total	**83,023,990**	**81,679,059**
Q1 2011	22,074,830	20,387,105
Q2 2011	18,409,043	20,136,282
Q3 2011	19,200,838	19,369,300
Q4 2011	23,388,668	20,194,446
2011 Total	**83,073,379**	**80,087,134**
Q1 2012	18,221,284	17,273,394
2012 Total	**18,221,284**	**17,273,394**
Cumulative Total	**$269,495,257**	**$305,991,850**
Projected Q2-Q4 2012	58,598,389	54,792,881
Projected 2013	36,575,418	34,934,170
2008-2013 Total	**$364,669,064**	**$395,718,901**

The cumulative totals of synergy savings to date show a clear distinction between the claimed Corporate Savings, the claimed Regulated Savings and the escalating amounts of Administrative & General expenses relative to KCPL's and GMO's peer utilities. The fact is that KCPL and GMO, while enjoying significant corporate retained benefits, have not flowed a comparable amount of regulated synergy savings to its regulated electric utility operations. During the three years post-acquisition, KCPL's and GMO's ratepayers continue to pay some of the highest, if not the highest A&G expenses in the region.

KCPL launched its Organizational Realignment/Voluntary Separation Program ("ORVS") on March 10, 2011. The resulting reduction of 140 KCPL employees resulted in significant savings KCPL and GMO have retained and will retain through regulatory lag. This program is further described by Staff Expert Charles R. Hyneman in the section of this Cost of Service Report entitled “March 2010 Organizational Realignment/Voluntary Separation (ORVS) Program”. Mr. Hyneman’s analysis shows that KCPL recovered all of its ORVS-related costs and realized a net savings of approximately $13 million. These employee reductions are additional acquisition synergies that are being realized less than three years subsequent to the acquisition of Aquila.

Staff Expert Arthur W. Rice has identified acquisition detriments related to premature retirements subsequent to the acquisition of Aquila. These acquisition detriments are further identified and explained in the Depreciation Section of this Cost of Service Report. Staff Expert Arthur W. Rice has identified $20.6 million of acquisition detriments for MPS and L&P related to the Aquila acquisition.

B. Qualifying Advanced Coal Project Credit for Iatan 2 Facility

Because of the acquisition of Aquila by Great Plains on July 14, 2008, all former Aquila employees were organized within KCPL—GMO has no employees. As such, no one represented GMO with respect to the decision not to seek any of the Iatan 2 Qualifying Advanced Coal Project Credit. Without a voice, GMO did not receive its proper share of these coal credits. Because of the corporate structure of Great Plains after the July 2008 acquisition, GMO was not afforded the opportunity to independently pursue the coal credits based on its 18% ownership of Iatan 2. Another co-owner of the Iatan 2 plant facility, Empire, received through an arbitration decision that it was entitled to its proportionate share of the coal credits. Had it not been for the acquisition of Aquila by Great Plains, GMO (as the former Aquila) would have been in the same position to pursue the coal credits as Empire and would have had the opportunity to receive the benefits of such coal credits.

Since GMO was not able to pursue the coal credits because of the acquisition, this is a merger/ acquisition detriment. Staff recommends the Commission give consideration to allowing further recovery beyond the effective date of rates in this case—January 2013—because of the acquisition/ merger detriment as well as the other reasons identified in this testimony.

For more detailed discussion of the Iatan 2 coal credits see the section of this Report entitled “Qualifying Advanced Coal Project Credit for Iatan 2 Facility.”

C. **Recommendations**

Staff does not recommend the continued amortization of transition costs through GMO's cost of service. While KCPL and GMO have identified a cumulative total of $269,495,257 of Regulated Savings and $305,991,850 of Corporate Savings, they have not complied with the Commission's requirement to demonstrate that test year savings exceed the amortized transition costs per the Commission Ordered Synergy Savings Tracking Model. Staff Experts Arthur W. Rice and Cary G. Featherstone have identified significant acquisition detriments that were not presented to the Commission when it ordered the amortization of transition costs. Through the projected effective date of rates in the 2012 Rate Cases, KCPL and GMO will have received $13.8 million of amortized transition costs through the rates.

In the Findings of Fact section of its Order in GMO's 2010 Rate Case in concerning this issue, the Commission found the following:

> 461. In Missouri, it is well established that there is a lag between when a cost or revenue is incurred and when that cost or revenue is reflected in rates. This is known as regulatory lag. [footnote omitted]
>
> 462. As a result of regulatory lag, if a utility experiences a cost decrease, there is a lag in time until that reduced cost is reflected in rates. During that lag, the Company shareholders reap, in the form of increased earnings, the entirety of the benefit associated with reduced costs. The Company shareholders also reap, in the form of decreased earnings, the entirety of the loss associated with increased costs.

In this case, the retained savings related to the 2011 Employee Reductions are a result of regulatory lag, which the Commission recognized as a source of increased earnings as a result of reduced costs without a change in its retail rates.

In its 2010 GMO Rate Case Order, the Commission found that shareholders had retained significant synergy savings:

> 472. As of September 1, 2009, the shareholders of KCP&L and GMO had realized over $59.3 million in synergy savings. [footnote omitted]
>
> 473. As of June 30, 2010, the shareholders of KCP&L and GMO had realized approximately $121 million in retained synergy savings. [footnote omitted]
>
> 474. KCP&L and GMO project that total synergy savings through 2013 will be $344 million. [footnote omitted] Of that amount, KCP&L and GMO project that ratepayers will receive $150 million. [footnote omitted]

The amount of savings through September 1, 2009 alone of $59.3 million exceeded the amount of deferred transition costs KCPL and GMO requested for recovery.

KCPL and GMO continue to realize new synergies related to the acquisition of Aquila. To the extent these synergies were not included in the test year of 2009 or the true-up cutoff of December 31, 2010 in the 2010 Rate Cases, those synergies are not currently being flowed to ratepayers and are being retained by shareholders. These are in addition to $121 million of retained synergies the Commission identified in its 2010 Order.

If the Commission authorizes the continued amortization of transition costs, Staff recommends that the transition costs be reduced by any retained savings related to the 2011 Employee Reductions in excess of severance costs (ORVS). Staff Expert Hyneman has identified $13 million of savings related to those employee reductions after the costs are considered regarding the employee reductions.

D. Amortization Period Relating to the Transition Costs

If the Commission authorizes the continued amortization of transition costs, Staff recommends a different amortization period than what the Commission determined was an appropriate period in its *Order* in GMO's 2010 Rate Case. In that *Report and Order*, the Commission found the following:

> 468. KCP&L and GMO began to retain synergy savings, in the form of reduced costs, immediately upon the closing of the acquisition. Given that KCP&L and GMO did not have its next rate case completed until September 1, 2009, the Great Plains shareholders retained the entirety of these synergy savings for that period of time. [footnote omitted]

Staff recommended, in its Cost of Service Report in GMO's 2010 Rate Case, that the amortization of transition costs should have began at the effective date of rates of KCPL's and GMO's first rate cases post-acquisition at September 1, 2009. In Finding of Fact 468 of its Order in GMO's 2010 Rate Case, the Commission recognized that KCPL and GMO began retaining synergy savings immediately upon the closing of the acquisition. In consideration of this finding, Staff recommends, rather than beginning the amortization of transition costs June 25, 2011 with respect to GMO's 2010 case, the start of the amortization should be September 1, 2009, which is the effective date of GMO's 2009 rate case (ER-2009-0090).

GMO was authorized to amortize transition costs pursuant to the Commission's *Report and Order.* As a result, an amount of transition costs exists in the test year cost of service.

Staff Adjustments E-136.1 and E-141.1 for MPS and E-144.1 and E-150.1 for L&P remove the test year amortization of transition costs from the cost of service.

Staff Expert/Witness: Keith Majors

XVI. Fuel Adjustment Clause

A. Recommendation

Staff recommends that the Commission approve, with modifications, the continuation of GMO's Fuel Adjustment Clause ("FAC"). Staff has reviewed the minimum filing requirements documents the Company provided in Schedules TRM-1, TRM-2, TRM-3 and TRM-4 attached to the pre-filed direct testimony of Company witness Tim M. Rush. Staff believes that with these documents the Company has complied with the minimum filing requirements contained in 4 CSR 240-3.161(3) to inform the public of the Company's requested continuation of and changes to its FAC in this case.

Staff recommends that the Commission order that the Company's FAC be modified to:

1. Change the sharing mechanism from 95% returned/recovered from the customers and 5% kept/absorbed by GMO to 85% returned/recovered from the customers and 15% kept/absorbed by GMO to provide the Company with a more appropriate incentive to keep its fuel and purchased power costs down;
2. Include any revenues from the sale of excess Renewable Energy Certificates ("RECs") in the FAC;
3. Specifically limit fuel hedging costs in the FAC to hedging costs for natural gas burned as fuel in the Company's generating units; and
4. Standardize the terminology in GMO's FAC tariff sheets to be consistent with changes Staff is recommending, when appropriate, for the FACs of the three investor-owned electric utilities with FACs. Staff's recommended changes to GMO's FAC tariff sheets will be provided in the Class Cost-Of-Service/Rate Design Staff Report to be filed on August 21, 2012.
5. 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 the transmission costs related to GMO's Crossroads Generating plant.

Further, Staff recommends that the Commission order GMO to continue to:

1. Exclude transmission costs related to its Crossroads generating plant from the Company's FAC; and
2. Provide or make available additional information and documents (as detailed later herein) to aid the Staff in performing FAC tariff, prudence and true-up reviews.

At this time Staff does not have an estimate for the base energy cost for GMO's FAC[126] in this case, but will include its estimate of the appropriate base energy cost when it files its Class Cost-of-Service/Rate Design Staff Report on August 21, 2012. The base energy cost in the FAC must be set equal to the base energy cost in the test year true-up total revenue requirement for this case so that customers or the company do not unfairly benefit at the expense of the other. Also, as part of its Class Cost-of-Service/Rate Design Staff Report, Staff will provide its recommended redline version of the GMO FAC tariff sheets.

B. History

Senate Bill 179[127] ("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 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 activities

[126] The various components of base energy cost are defined and are the same as the components of total energy cost: TEC = (FC + EC + PP + TC – OSSR) in the definition contained in KCP&L Greater Missouri Operations Company P.S.C. MO. No. 1, Original Sheet Nos. 127.7 and 127.8.
[127] Section 386.266, RSMo. 2010 Cum. Supp.

in a manner that allowed it to reliably serve its customers at a cost lower than what was included in its revenue requirement in the general electric rate proceeding, the savings were retained by the electric utility. If actual fuel and purchased power costs were greater than the cost included in the revenue requirement in the 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 and ER-2010-0356, the Commission authorized continuation with modifications of GMO's FAC. The primary features of GMO's present FAC (tariff sheet numbers 127.6 through 127.10) 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") previously known as Cost Adjustment Factors ("CAFs") 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 GMO service voltage levels, rounded to the nearest $0.0001, 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.

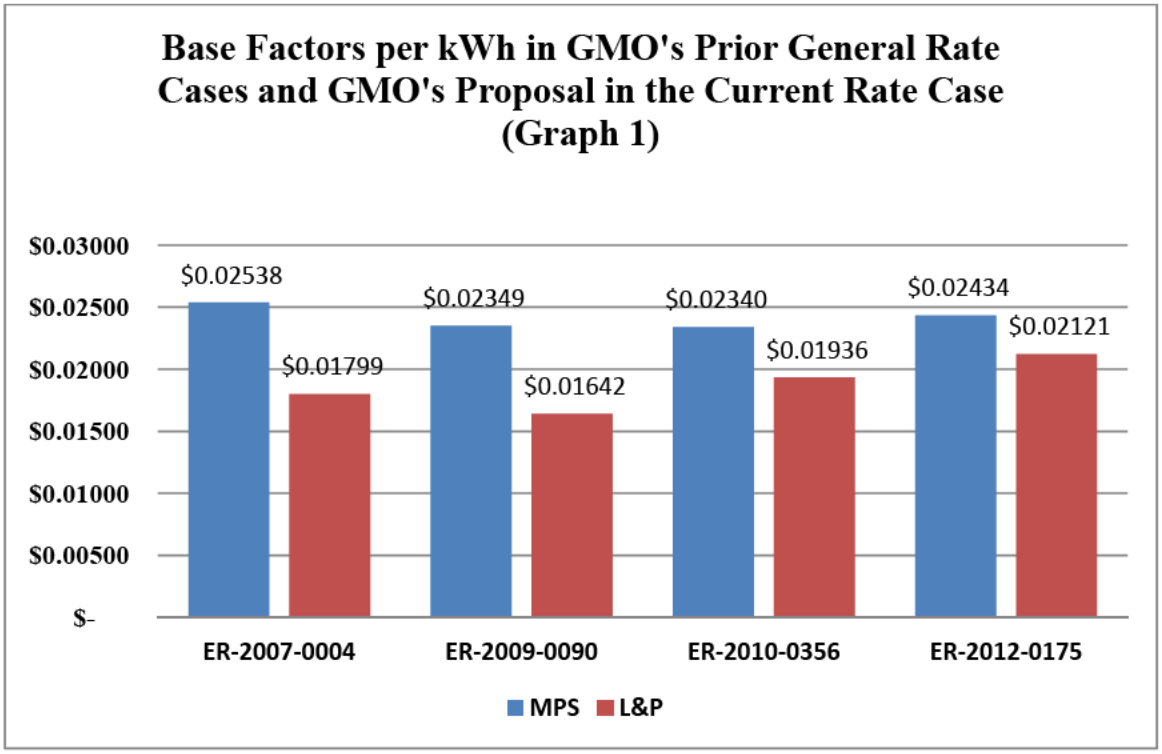
The MPS and L&P base factors (base energy cost per kWh rates) were originally set in GMO's 2007 rate case (Case No. ER-2007-0004) to be $0.02538 per kWh for MPS and $0.01799 per kWh for L&P. In GMO's 2009 rate case (Case No. ER-2009-0090), the Company did not propose to re-base the base factors. Despite 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.[128] 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 rate. In its *Report and Order* the Commission resolved this contested issue and directed that the base energy cost per kWh rates be re-based.[129] 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 the current rate case (Case No. ER-2012-0175), GMO is proposing to re-base the base factors to $0.02434 per kWh for MPS and $0.02121 per kWh for L&P. Staff will file its recommended base energy cost per kWh rates with its Class Cost-of-Service/Rate Design Report on August 21, 2012.

Graph 1 below shows GMO's base factors throughout the history of GMO's FAC. The base factors range from a low of $0.02340 to a high of $0.02538 for MPS and from a low of $0.01642 to a high of $0.02121 for L&P. By re-basing the base factor in each electric general rate case, the cost the customers pay for fuel and purchased power is closer to the actual cost the Company pays. If it is not rebased, the Company would not receive a significant amount of the fuel and purchased power costs for up to nine months after the costs were actually incurred.

Continued on next page.

[128] *Non-Unanimous Stipulation and Agreement*, filed on May 22, 2009.
[129] See Case No. ER-2010-0356: *Report and Order* dated May 4, 2011 concerning Decision – FAC Rebasing on pages 208 – 209.



C. Summary of GMO's Fuel and Purchased Power Costs Net of Off-System Sales Revenues

Graph 2 below shows, for each full accumulation period[130] ("AP"), a summary of GMO's actual fuel and purchased power costs net of off-system sales revenues ("total energy costs"), base fuel and purchased power costs net of off-system sales billed revenues ("base energy costs"), and the under- and over-collection of total energy costs compared to base energy costs.

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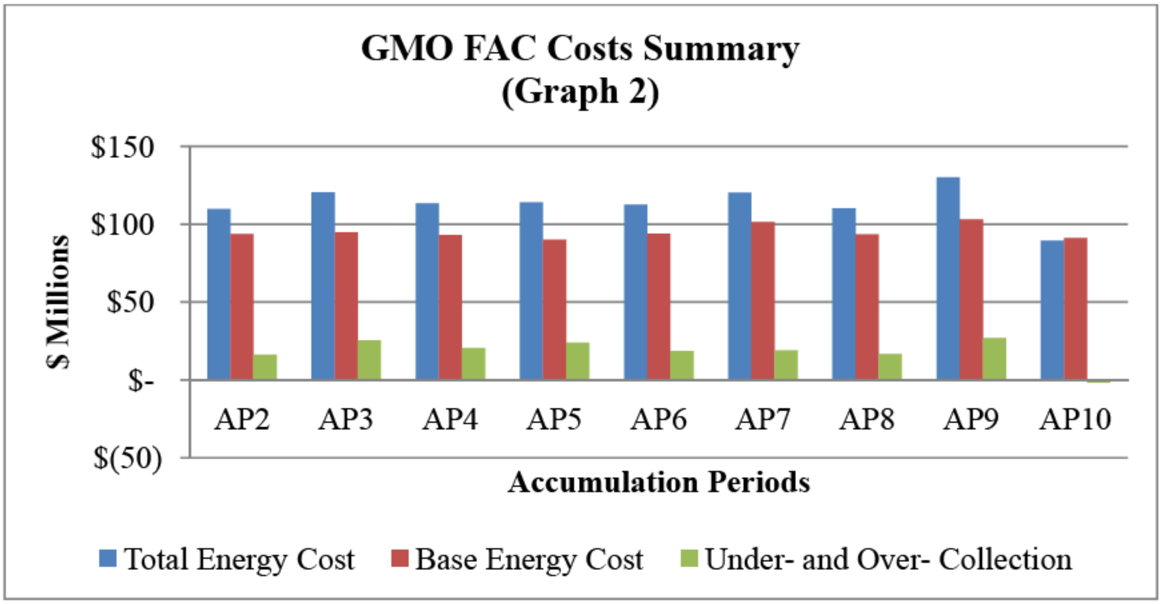
[130] AP1 was not a full accumulation period.



The time periods and associated case numbers of the Accumulation Periods follow:

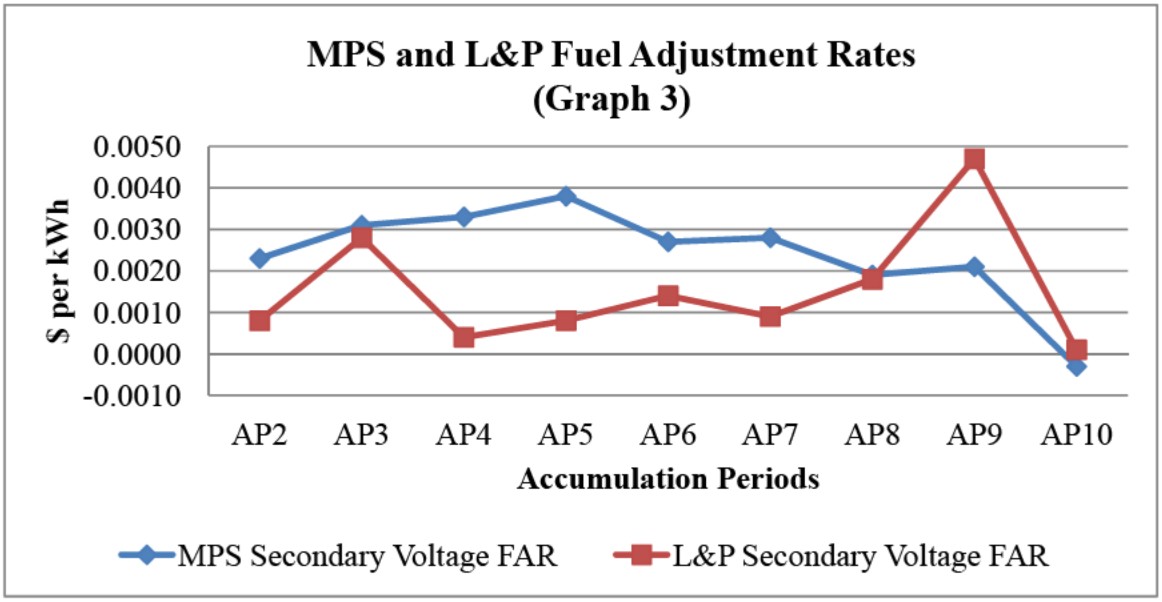
Accumulation Period	Case Number	Time Period
AP2	EO-2008-0415	Dec 2007 - May 2008
AP3	EO-2009-0254	Jun 2008 - Nov 2008
AP4	EO-2010-0002	Dec 2008 - May2009
AP5	EO-2010-0191	Jun 2009 - Nov 2009
AP6	ER-2010-0385	Dec 2009 – May 2010
AP7	ER-2011-0179	Jun 2010 - Nov 2010
AP8	ER-2011-0417	Dec 2010 - May 2011
AP9	ER-2012-0197	Jun 2011 - Nov 2011
AP 10	ER-2012-0478	Dec 2011 - May 2012

Graph 2 above shows that in each of its accumulation periods AP2 through AP9, GMO's actual total energy costs exceeded the base energy costs billed to customers. However, during AP10, GMO's base energy costs billed to customers exceeded the actual total energy costs as a result of the base energy cost per kWh rates being re-based in GMO's last general rate case, lower natural gas prices, falling price of purchased power during the period, and the abnormally warm weather[131] during the accumulation period.

[131] AP10 included a portion of the mild 2011-2012 winter and the warmer than normal spring of 2012.

1. <u>Fuel Adjustment Rates</u>

Graph 3 below shows GMO's current period FARs[132] for accumulation periods AP2 through AP10.



The following table shows the reasons for the most significant fluctuations of the current period FARs for AP3, AP9 and AP10 for MPS and/or L&P:

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[132] For example, the current period FARs for service at secondary voltage for AP9 can be found on line 16 of KCP&L Greater Missouri Operations Company P.S.C. MO. No. 1, 1st Revised Sheet No. 127.10.

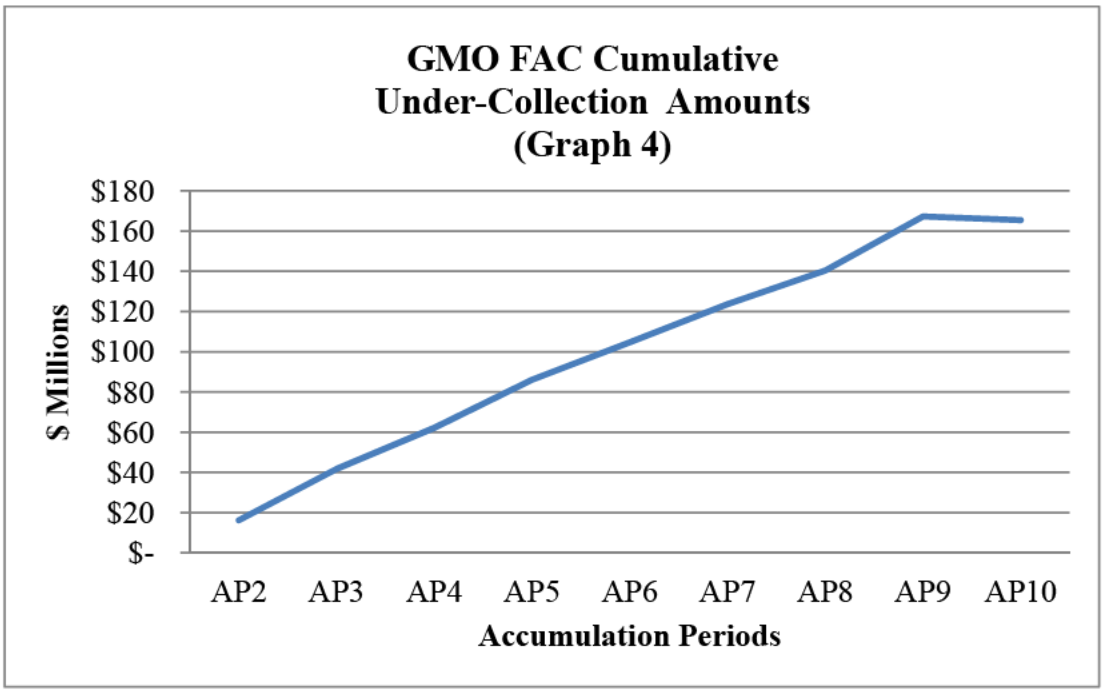
AP3-L&P	During AP3, Iatan 1, of which L&P is assigned 127 MW, experienced a significant outage for half of October and all of November, 2008. The Lake Road generating units, of which L&P is assigned 99 MW, also experienced outages. Therefore two of L&P's cheapest generating sources were not available resulting in increased purchased power costs, which resulted in an increase in the FARs.
AP9-L&P	L&P is assigned 127 MW of Iatan 1, 53 MW of Iatan 2, and 99 MW of Lake Road. During AP9, L&P's coal generating units were significantly impacted by the 2011 Missouri River flooding, which disrupted rail service for coal deliveries forcing coal conservation and reduced generation at these plants requiring the use of more expensive generation and purchased power. This resulted in a significant increase in the FAR.
AP10-MPS	As a result of re-basing the base factors approved in Case No. ER-2010-0356, a decrease in natural gas prices, and a decrease in purchased power prices, the base energy costs exceeded the actual total energy costs resulting in a decrease to the FAR for AP10.
AP10-L&P	As a result of re-basing the base factors approved in Case No. ER-2010-0356, the base energy costs were only slightly below the actual total energy costs resulting in a decrease to the FAR for AP10.

GMO's AP10 FAR request was filed June 29, 2012 in Case No. ER-2012-0478. On July 30, 2012, Staff made its recommendation that the Commission approve the Company's proposed AP10 FAR request. As of the filing date of this report, the Commission has not issued its decision in Case No. ER-2012-0478. According to GMO witness Linda J. Nunn's direct testimony in Case No. ER-2012-0478, the decline in the FARs from AP9 to AP10 was due to the following:

> Fuel and purchased power costs net of off system sales revenues were rebased in the 2010 Case. The new base rates became effective on July 1, 2011. Because of the inclusion of a more current level of costs included in base rates, the falling cost of natural gas and the corresponding falling cost of purchased power, the current six month accumulation period shows a declining level of fuel and purchased power costs net of off system sales.

Staff agrees with this quotation from GMO witness Linda J. Nunn's direct testimony. Staff notes that re-basing the base factor approved in Case No. ER-2010-0356 helped contribute to a decrease of the FARs during AP10 (November 2011-May 2012).

Graph 4 and Graph 5 illustrate the following information for the previous nine (9) full accumulation periods: 1) cumulative amount of the difference between actual total energy costs and the base energy costs as calculated using the base energy cost per kWh rates in GMO's FAC tariff sheets, and 2) percentage of cumulative under-collection of the difference between actual total energy costs and the base energy costs billed to customers:



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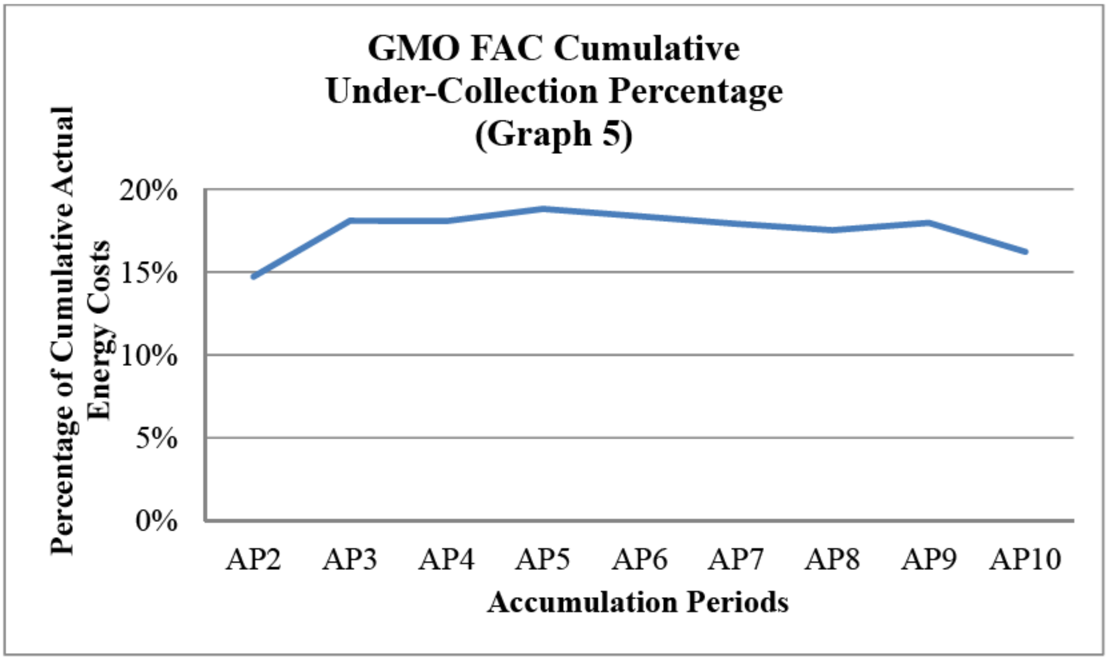

From the above graphs Staff observes that the FAC cumulative under-collected amount over four and one-half years of $165 million (16 percent of actual total energy costs of approximately $1.02 billion) is significant to GMO. Staff's analysis and discussion in the **Sharing Mechanism of FAC** section which follows suggests that without a FAC (GMO being responsible for 100% of actual total energy costs) GMO would have lost approximately 36.4 percent of its test year net income before taxes ("NIBT") due to under-collection of fuel and purchased power costs less off-system sales revenue during AP2 through AP10.

2. <u>Sharing Mechanism of FAC</u>

The Staff recommends changing the FAC sharing mechanism from 95%/5% to 85%/15% for the following reasons:

- The Commission stated in its *Report and Order* in Case No. ER-2007-0004 that the objective of a FAC is to provide an incentive for the Company to "keep its fuel and purchased power costs down."
- KCPL's off-system sales margin proposal in its current rate case, Case No. ER-2012-0174 demonstrates a willingness on the part of Great Plains Energy to

accept a 25% share of risk related to the uncertainty of KCPL's cost of fuel and purchased power net of off-system sales revenue.

- GMO's total indifference to the amount of net energy costs because GMO has a FAC, as discussed by GMO witness Mr. William E. Blunk demonstrates that GMO is not incented or motivated by the 5% share of risk to keep fuel and purchased power costs down.
- GMO's reluctance to rebase the base energy costs in Case Nos. ER-2009-0090 and ER-2010-0356 demonstrates its indifference and insensitivity concerning the value of sending the correct pricing signal to customers when changes to base energy costs are first known and a willingness to use its FAC for its advantage to the disadvantage of its customers.
- GMO's energy purchases from KCPL during 2011 demonstrate Great Plains Energy's, KCPL's and GMO's willingness to use GMO's FAC to flow market-based costs to GMO to be passed on to its retail customers when the lower costs of a contract with ** _____ ** could have been available, but kept for the benefit of KCPL.
- GMO's 5% share of the total under-collection amount of $165 million during the last nine (9) full accumulation periods is $8.3 million and represents 1.8% of the four and one-half-year GMO net income before taxes ($455 million). Fifteen percent (15%) of GMO's share of the total under-collection amount of $165 million during the last nine (9) full accumulation periods is $24.8 million and represents 5.5 percent (5.5%) of GMO's four and one-half-year NIBT ($455 million) which would provide a stronger incentive to keep GMO's fuel and purchased power costs down.

As stated in the first bullet point above, in Case No. ER-2007-0004, the Commission stated the objective of a FAC sharing mechanism is to provide an incentive for the Company to "keep its fuel and purchased power costs down." To do so requires incenting the utility to develop and manage an effective energy procurement process which minimizes energy costs while managing risk of loss of energy supply. The Commission first expressed its view in its

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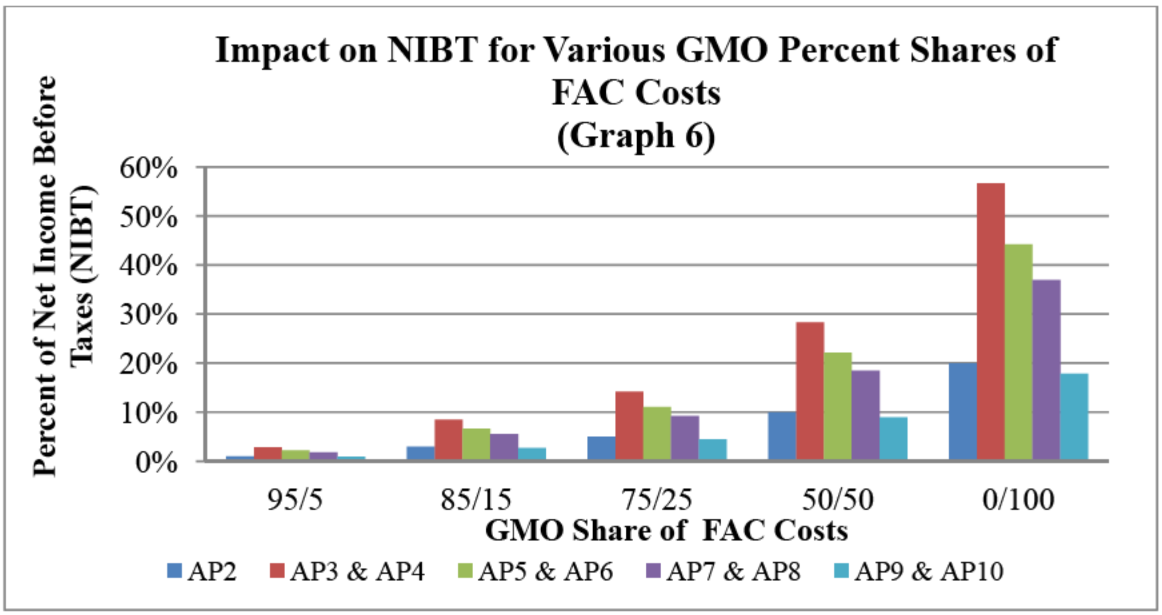
Report and Order in Case No. ER-2007-0004 where it first established the current 95%/5% sharing mechanism when it stated on page 54:

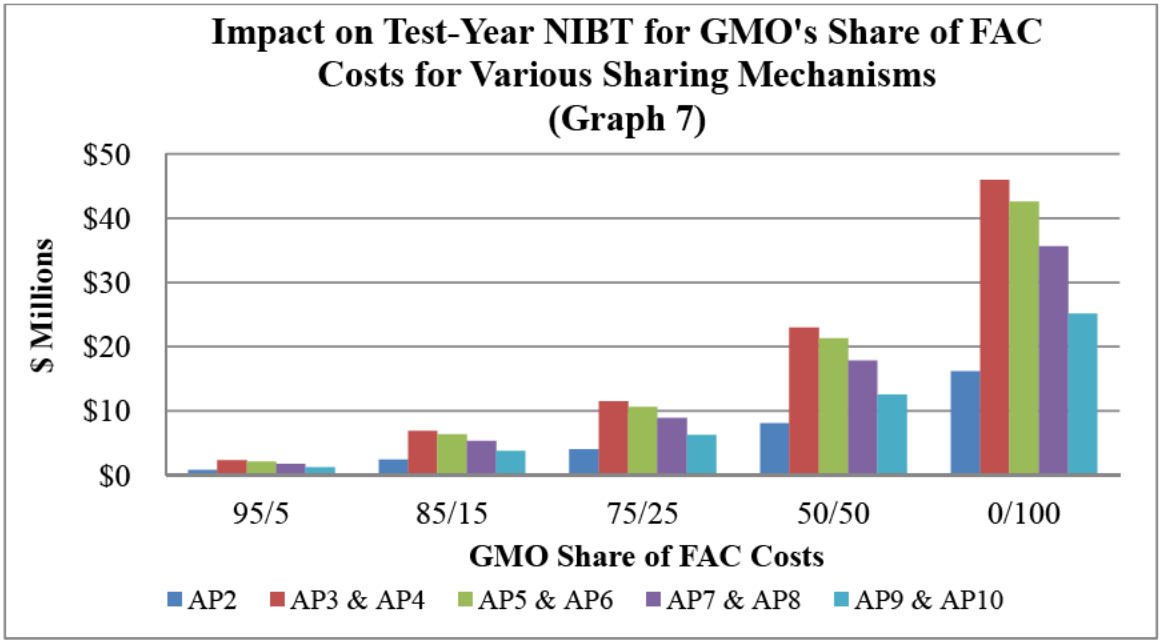
> The Commission also finds after-the-fact prudence reviews alone are insufficient to assure Aquila will continue to take reasonable steps to keep its fuel and purchased power costs down, and the easiest way to ensure a utility retains the incentive to keep fuel and purchased power costs down is to not allow a 100% pass through of those costs.

Staff has evaluated the impact of GMO's FAC on GMO's NIBT over the previous nine (9) full accumulation periods with the current 95%/5% sharing mechanism and what it would have been with several other selected sharing mechanisms. Staff notes that AP2 is a six-month period and reflects NIBT for six months. AP3&AP4, AP5&AP6, AP7&AP8, and AP9&AP10 reflect NIBT on an annual basis. The results of Staff's evaluation follow in Graph 6:



Through this analysis Staff estimates that GMO's 5% share of the total under-collection amount of $165 million during the last nine (9) full accumulation periods is $8.3 million and represents 1.8% of GMO's four and one-half-year NIBT ($455 million) for this same period of time. Similarly, Staff estimates that for Company shares of 15%, 25%, 50%, and 100% of the total under-collection amount during the previous nine (9) accumulation periods represent approximately 5.5%, 9.1%, 18.2%, and 36.4% of GMO's four and a half-year NIBT for this same period of time respectively.

The corresponding dollar amounts of the total under-collected amount of $165 million during the previous nine (9) accumulation periods that the Company would have been responsible for if the Company's share had been 5%, 15%, 25%, 50%, and 100% are illustrated in Graph 7.



Staff considers the average accumulation period amount of $919,000 the Company has been responsible for under the current 95%/5% sharing mechanism during the last nine accumulation periods out of an average accumulation period total under-collected amount of $18.4 million to be an insufficient incentive for GMO to "keep its fuel and purchased power costs down" by developing and managing an effective energy procurement process to minimize energy costs while managing risk of loss of energy supply.

If Staff's recommended 85%/15% sharing mechanism had been in place for the last nine (9) accumulation periods it would have resulted in GMO being responsible for an average accumulation period of $2.8 million of the under-collected amount of the FAC. Measured differently, this would be approximately 5.5% of GMO's NIBT during that same period.

By being responsible for 15% of FAC over- and under-collection amounts, GMO would have had a greater incentive to keep its fuel and purchased power costs down—and to minimize fuel and purchased power costs less off-system sales revenues while managing risk of loss of energy supply.

3. Kansas City Power and Light Company's Off-System Sales Margin Proposal

In KCPL's current rate case, Case No. ER-2012-0174, KCPL proposes the Commission approve a sharing of KCPL's off-system sales margin. KCPL witness Michael M. Schnitzer's prefiled direct testimony includes the following:

> KCPL has proposed to establish the initial offset for off-system sales margin at the 40th percentile of my probability distribution. In a departure from past proposals for Margin during the last four rate cases, KCPL proposes to share 25 percent of the downside risk with customers below the 40th percentile, while retaining 75 percent of this risk at the Company. Between the 40th percentile and the 60th percentile, all of the excess of realized Margin over the 40th percentile value would be returned to ratepayers. Above the 60th percentile, KCPL proposes to share in 25 percent of the upside difference between realized Margin and the 60th percentile value. The customers would retain the other 75 percent.[133]

While not completely comparable to GMO's FAC sharing mechanism, it is Mr. Schnitzer's proposal that a modified 75%/25% sharing mechanism of off-system sales margin is acceptable KCPL.

KCPL and GMO are separate legal entities, but operate under the same management. KCPL's willingness to have a modified sharing of off-system sales different from 95%/5% supports Staff's recommendation that GMO's FAC sharing mechanism be changed to 85%/15%.

4. GMO's Indifference to the Amount of Net Energy Costs

In GMO's most recent prudence review hearing in Case No. EO-2011-0390 on June 5, 2012, Mr. William Edward Blunk who is Supply Planning Manager for both KCPL and GMO stated during redirect questioning by GMO outside attorney Mr. Jim Fischer the following:

> Q. Does any of this discussion that you have here on page 17[sic] or 18 suggest that the company isn't hedging to protect customers?
>
> A. The purpose of our hedging program really is to protect customers. The fuel clause, the customer is the one that bears the energy market risk. So all the hedging is for the benefit of the customer. There is not benefit to the company of any of this hedging. There is no benefit to the company.

[133] Direct Testimony of Michael M. Schnitzer, Page 33, Line 3 through Line 11.

> Q. So you're indifferent whether you—if the Commission says don't cross hedge anymore, what would be the company's response?
>
> A. We would probably stop hedging, hedging altogether. There's no -- the company has no benefit from employing this hedging program. It is strictly for the benefit of the customer.
>
> Q. Does the company – does Kansas City Power & Light Company, to your knowledge, hedge in Kansas?
>
> A. No. We do not hedge in Kansas because in Kansas KCPL has a fuel clause. Again, when there's a fuel clause in place, the hedging is for the benefit of the customer. There is no benefit to the company for a hedge program. There's no motive, no benefit, no reason to do it.[134]

While this excerpt from Mr. Blunk's redirect appears to suggest hedging is for the benefit of the customer, the last statements raise questions as to the relationship of hedging and a fuel adjustment clause.

More telling, later on during the same redirect questioning, Mr. Blunk made statements related to the company and ratepayer perspective that relay GMO's indifference to its actual amount of fuel cost and purchased power costs net of off-system sales revenues. This indifference is a significant concern and demonstrates why the current sharing mechanism is not a proper incentive for GMO to keep its fuel and purchased power costs down. Beginning with a question from GMO outside attorney, Mr. Fischer, and continuing with Mr. Blunk's response:

> Q. From the shareholder perspective, assuming that you have an FAC in place, do you care if a Katrina hits?
>
> A. As a share – well, from the company's perspective, its risk goes through the fuel clause, so no. As a ratepayer, I'm a GMO ratepayer, I do care.
>
> Q. You care very much?
>
> A. I do.[135]

Finally during the same redirect questioning by GMO outside attorney Mr. Fischer, Mr. Blunk said:

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[134] Transcript for EO-2011-0390v4 Page 124, Line 15 through Page 125 Line 13.
[135] Transcript for EO-2011-0390v4 Page 130, Line 9 through 16.

Q. Well, since you had all those gains, is that a good thing?

A. I don’t know if you’d say it’s good or bad. It’s – you need to take the two, and the two of them wash each other out.

Q. So the company’s indifferent, is that what you’re saying?

A. Yes. Doesn’t matter to the company.[136]

5. <u>Contracts</u>

GMO/KCPL/ ________ ** Contracts**

On ** ____ ____ ________________ ** because GMO was going to be short of capacity. GMO assigned ** ____ ____ ________________ ** to meet GMO’s capacity needs.

On ** ____ ____ ________________________________ ** due to the Missouri River flood. ** ____ ________________ **

Staff receives monthly reports as required by rule 4 CSR 240-3.190(1)(E) (“rule 3.190”).[137] According to these reports and Graphs 8 and 9 below, the dollar per MWh that GMO purchased power from KCPL while KCPL was purchasing energy ** __________ ** was generally higher than the dollar per MWh that KCPL purchased power ** __________ ** on an average daily basis giving KCPL a net increase of $3.9 million throughout the term of the contract between KCPL and ** _____ **. GMO then passed those additional purchased power costs onto its customers through its FAC, for which customers were responsible for $3.7 million (95%) and shareholders $195,000.

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[136] Transcript for EO-2011-0390v4 Page 136, Line20 through Page 137 Line 2.

[137] 4 CSR 240-3.190(1)(E). For requirement 1 (E) the utilities are required to report megawatt amount and delivery prices of hourly purchases and sales of electricity; the utilities are also to report the counterparties and the terms of purchases and sales as well as any adjustments made to the price and the time period over which the adjustment was made.

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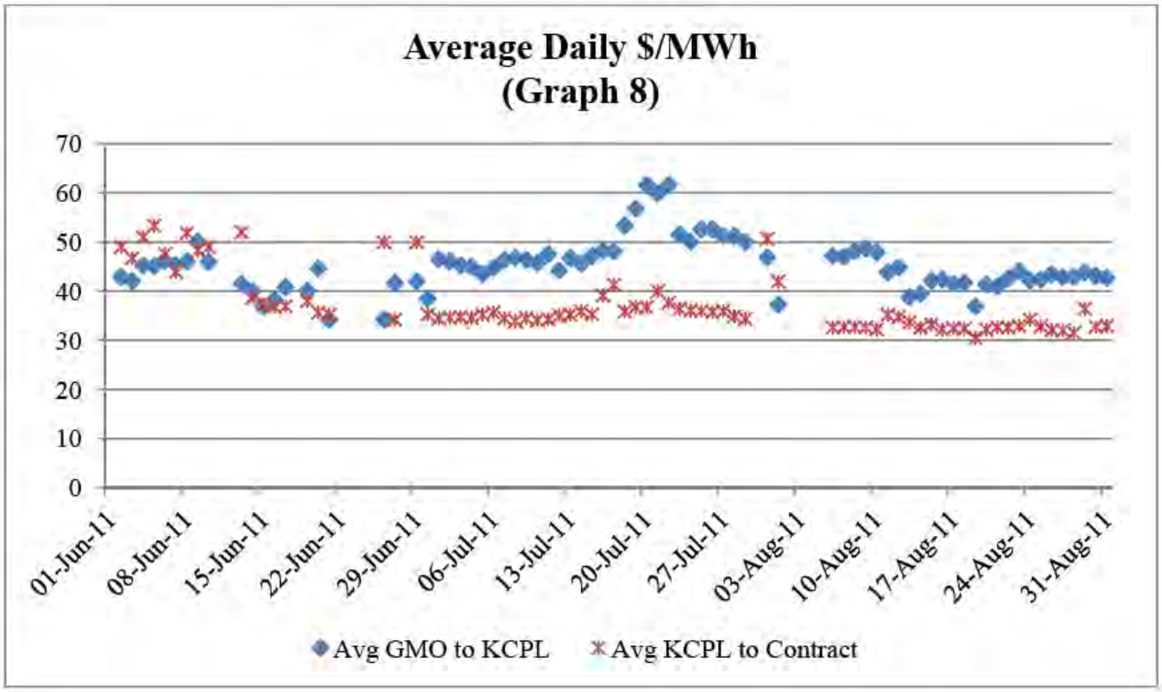
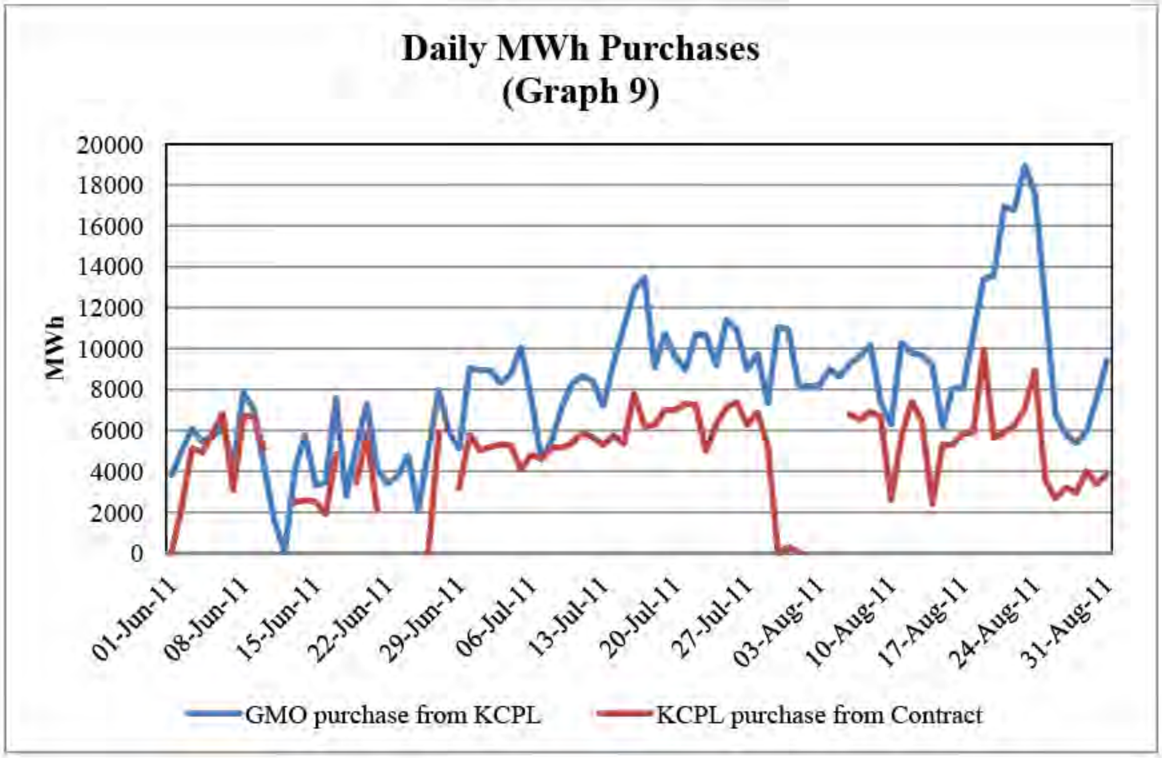
The Graph 8 below shows the average daily dollars per MWh KCPL purchased from its contract and then sold to GMO.



Graph 9 below shows the daily energy per MWh KCPL purchased from its contract and the MWh KCPL sold to GMO.

Continued on next page.



Based on the graphs above, this begs the question why, since KCPL manages GMO, GMO did not enter into a separate contract with **_____ ** instead of KCPL, or why KCPL did not allocate GMO a portion of the contract where GMO could have purchased the energy at cost, saving GMO's customers $3.6 million (95%).

Staff's proposal of an 85%/15% sharing mechanism would provide GMO's managers the incentive to manage GMO independently, and keep fuel and purchased power costs down, to the benefit of its customers.

6. Recommendation Concerning FAC Sharing Mechanism

Given the above analysis of GMO's FAC, Staff recommends that the Commission change the current 95%/5% FAC sharing mechanism to an 85%/15% FAC sharing mechanism. Staff considers an 85% share of FAC over- and under-collection amounts to be a point where ratepayers continue to take on a significant portion of the risk of actual FAC costs, while giving GMO more incentive to keep fuel and purchased power costs down. With this modification, GMO's retail customers would pay 85% of any increase in actual fuel and purchased power costs net of off-system sales revenues above its fuel and purchased power costs net of off-system sales

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revenues billed to customers in general rates and receives a refund for 85% of any decrease. At the same time, GMO would absorb 15% of any increase in actual fuel and purchased power costs net of off-system sales revenues billed to customers and keep 15% of any decrease.

7. Renewable Energy Certificate Revenues

In conjunction with its PPAs for wind energy and the small methane plant in St. Joseph, Missouri, GMO acquires Renewable Energy Certificates. Some of these are used meet the Renewable Energy Standard in Missouri. Prudent management of these certificates would include selling those not needed to meet the Renewable Energy Standard Law before they expire. Because these certificates are tied to energy that the GMO customers paid for through PPAs, Staff recommends that the Commission require any future revenues from the sale of Renewable Energy Certificates be flowed through GMO's FAC as an off-set to costs in the calculation of GMO's FAR.

8. Hedging Costs for Natural Gas Used for Fuel in the Company's Generating Stations

In its third prudence review of GMO's FAC costs (Case No. EO-2011-0390), Staff recommended a disallowance related to use of natural gas hedges for natural gas not burned in its generating units. The Commission has yet to rule in that case. However, regardless of whether or not the Staff's recommended prudence disallowance is adopted in that case, Staff believes spot market cross-hedging costs should not be allowed to flow through GMO's FAC in the future. Staff recommends that the Commission limit hedging costs in GMO's FAC to only hedging costs for natural gas actually burned as fuel in its generating units. Staff will recommend tariff language specific to what type of hedging is allowed in its Class Cost-of-Service/Rate Design Report to be filed in this case on August 21, 2012.

9. Transmission Costs and Revenues

Staff recommends that GMO's FAC continue to only include the transmission costs GMO incurs that are necessary for it to serve the load requirements of its customers and those that are necessary for it to make OSS, excluding the transmission costs related to GMO's Crossroads generating station. No other transmission costs or revenues should flow through GMO's FAC without GMO first proposing that they do so in a general rate proceeding where all parties have an opportunity to make recommendations to the Commission on the appropriateness of doing so. Staff recommends that the Commission clarify that only the transmission costs GMO incurs that are necessary to receive purchased power to serve the load requirements of its customers and those that are necessary for it to make OSS are flowed through its FAC by specifically stating that only these transmission costs and revenues are allowed to flow through GMO's FAC, excluding the transmission costs related to GMO's Crossroads generating station. Doing so will avoid potential confusion in future prudence audits. Staff will propose tariff language changes to effectuate this clarification in the Staff's Class Cost-of-Service/Rate Design Report to be filed on August 21, 2012.

10. Changes to FAC Tariff Sheet Terminology

The Commission, Staff and the electric utilities have been refining FACs, and the tariff sheets that implement them, since the Commission first authorized Aquila, Inc., to use a FAC in Case No. ER-2007-0004. While each utility's FAC complies with the same Commission rules, each utility has unique FAC tariff sheets with unique acronyms and definitions. Different nomenclature for the same thing is used across the utilities and sometimes even within a single utility's tariff sheets. For example, the dollar amount of the adjustment is referred to in GMO's FAC tariff sheets as the "Fuel Adjustment Clause (FAC)," "Fuel and Purchased Power Adjustment," "FPA," "FAC costs," and just "FAC." The Empire District Electric Company ("Empire") refers to it as "FAC" and "Fuel Adjustment Clause." The adjustment is only referred to in Union Electric d/b/a Ameren Missouri's ("Ameren Missouri") tariff sheets as the "Third Subtotal." Staff proposes that the dollar amount of the adjustment be referred to uniformly as the "Fuel and Purchased Power Adjustment" or "FPA." Staff made this same recommendation in the pending Ameren Missouri rate case, Case No. ER-2012-0166, and will make the same recommendation in the upcoming Empire rate case, Case No. ER-2012-0345.

This is just one of many "clean-up" changes that Staff will recommend in its Class Cost-of-Service/Rate Design Report to be filed in this case on August 21, 2012. Staff has been working with all of the electric utilities, including GMO, on these proposals and hopes to come to a consensus on the terminology to be used within the electric utility industry in Missouri. It is not Staff's intent to change the meaning of different phrases in each utility's FAC tariff sheets, but to help avoid and minimize confusion when discussing the FACs of electric utilities in Missouri.

11. <u>Additional Filing Requirements</u>

Similar to recommendations made in Case Nos. ER-2009-0090 and ER-2010-0356, Staff again recommends that the Commission order GMO to do the following to aid the Staff in performing FAC tariff, prudence and true-up reviews:

- As part of the information GMO submits when it files a tariff modification to change its Fuel and Purchased Power Adjustment rate, include GMO's calculation of the interest included in the proposed rate;
- Maintain at GMO's corporate headquarters or at some other mutually agreed upon place within a mutually agreed upon time for review, a copy of each and every nuclear fuel, coal and transportation contract GMO has that is in or was in effect for the previous four years;
- Within 30 days of the effective date of each and every nuclear fuel, coal and transportation contract GMO enters into, provide both notice to the Staff of the contract and opportunity to review the contract at GMO's corporate headquarters or at some other mutually agreed upon place;
- Maintain at GMO's corporate headquarters or provide at some other mutually agreed upon place within a mutually agreed upon time, a copy for review of each and every natural gas contract GMO has that is in effect;
- Within 30 days of the effective date of each and every natural gas contract GMO enters into, provide both notice to the Staff of the contract and opportunity for review of the contract at GMO's corporate headquarters or at some other mutually agreed upon place;
- Provide a copy of each and every GMO hedging policy that is in effect at the time the tariff changes ordered by the Commission in this rate case go into effect for Staff to retain;
- Within 30 days of any change in a GMO hedging policy, provide a copy of the changed hedging policy for Staff to retain;

- Provide a copy of GMO's internal policy for participating in the SPP, including any GMO sales/purchases from that market that are in effect at the time the tariff changes ordered by the Commission in this rate case go into effect for Staff to retain;

- If GMO revises any internal policy for participating in the SPP, within 30 days of that revision, provide a copy of the revised policy with the revisions identified for Staff to retain.

Staff Expert/Witness: Matthew J. Barnes

D. Fuel Adjustment Clause Heat Rate and Efficiency Testing

If an electric utility requests that a FAC be continued or modified, Commission Rule 4 CSR 240-3.161(3)(Q) requires that it file specific information as part of its direct testimony in a general rate proceeding as detailed in the following excerpt:

> (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[138]. Approval of the initial heat rate testing schedule and plan was ordered in Case No. EO-2008-0156. GMO's FAC was continued in Case No. ER-2009-0090 and Case No. ER-2010-0356. GMO has requested the FAC be continued in the current general rate proceeding ER-2012-0175.

Company witness Burton L. Crawford prefiled in his testimony the results of the most recent heat rate/efficiency tests for GMO's generating units. Staff has reviewed the summary results of those tests and compared them with the summary results in its previous general electric rate proceeding, Case No. ER-2010-0356[139].

The new heat rate/efficiency testing information and results for the generating units appears to be reasonable.

Staff Expert/Witness: Michael E. Taylor

[138] The FAC was initially granted to Aquila, Inc.
[139] The following generating units were not included in ER-2010-0356 due to not being operational or included in the Company's generating assets at that time: Crossroads 1, 2, 3, and 4 and Iatan 2.

XVII. Appendices

Appendix 1 - Staff Credentials

Appendix 2 - Support for Staff Cost of Capital Recommendation
-David Murray

Appendix 3 – Other Staff 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 General Rate Increase for Electric Service	))))	Case No. ER-2012-0175

AFFIDAVIT OF MATTHEW J BARNES

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Matthew J. Barnes, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Matthew J. Barnes

Matthew J. Barnes

Subscribed and sworn to before me this 9th day of August, 2012.

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

D. Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement General Rate Increase for Electric Service	))))	Case No. ER-2012-0175

AFFIDAVIT OF ALAN J. BAX

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Alan J. Bax, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Alan J. Bax

Alan J. Bax

Subscribed and sworn to before me this 9th day of August, 2012.

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

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement General Rate Increase for Electric Service	))))	Case No. ER-2012-0175

AFFIDAVIT OF KIM COX

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Kim Cox, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Kim Cox

Kim Cox

Subscribed and sworn to before me this 9th day of August, 2012.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
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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 General Rate Increase for Electric Service	))))	Case No. ER-2012-0175

AFFIDAVIT OF NATELLE DIETRICH

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Natelle Dietrich, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Natelle Dietrich

Natelle Dietrich

Subscribed and sworn to before me this 9th day of August, 2012.

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

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement General Rate Increase for Electric Service	))))	Case No. ER-2012-0175

AFFIDAVIT OF DAVID W. ELLIOTT

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

David W. Elliott, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

D. W. Elliott

David W. Elliott

Subscribed and sworn to before me this 9th day of August, 2012.

D. SUZIE MANKIN
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State of Missouri
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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 General Rate Increase for Electric Service	))))	Case No. ER-2012-0175

AFFIDAVIT OF CARY G FEATHERSTONE

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

Cary G. Featherstone, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Cary G Featherstone

Cary G Featherstone

Subscribed and sworn to before me this 9th day of August, 2012.

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

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement General Rate Increase for Electric Service	))))	Case No. ER-2012-0175

AFFIDAVIT OF PATRICIA GASKINS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Patricia Gaskins, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Patricia Gaskins
Patricia Gaskins

Subscribed and sworn to before me this 9th day of August, 2012.

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

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement General Rate Increase for Electric Service	))))	Case No. ER-2012-0175

AFFIDAVIT OF RANDY S. GROSS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Randy S. Gross, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Randy S. Gross

Subscribed and sworn to before me this 9th day of August, 2012.

D. SUZIE MANKIN
Notary Public - Notary Seal
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Commissioned for Cole County
My Commission Expires: December 08, 2012
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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 General Rate Increase for Electric Service	))))	Case No. ER-2012-0175

AFFIDAVIT OF V. WILLIAM HARRIS

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

V. William Harris, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

V. William Harris

V. William Harris

Subscribed and sworn to before me this 9th day of August, 2012.

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

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement General Rate Increase for Electric Service	))))	Case No. ER-2012-0175

AFFIDAVIT OF CHARLES R. HYNEMAN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Charles R. Hyneman, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

CHarles R Hyneman

Charles R. Hyneman

Subscribed and sworn to before me this 9th day of August, 2012.

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

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement General Rate Increase for Electric Service	))))	Case No. ER-2012-0175

AFFIDAVIT OF THOMAS M. IMHOFF

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Thomas M. Imhoff, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Thomas M. Imhoff

Thomas M. Imhoff

Subscribed and sworn to before me this 9th day of August, 2012.

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

D. Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement General Rate Increase for Electric Service))))	Case No. ER-2012-0175

AFFIDAVIT OF HOJONG KANG

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Hojong Kang, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Hojong Kang

Hojong Kang

Subscribed and sworn to before me this 9th day of August, 2012.

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

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement General Rate Increase for Electric Service	))))	Case No. ER-2012-0175

AFFIDAVIT OF ROBIN KLIETHERMES

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Robin Kliethermes, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Robin Kliethermes

Robin Kliethermes

Subscribed and sworn to before me this 9th day of August, 2012.

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

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement General Rate Increase for Electric Service	))))	Case No. ER-2012-0175

AFFIDAVIT OF SHAWN E. LANGE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Shawn E. Lange, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Shawn E. Lange

Shawn E. Lange

Subscribed and sworn to before me this 9th day of August, 2012.

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AFFIDAVIT OF KAREN LYONS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Karen Lyons, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Karen Lyons

Karen Lyons

Subscribed and sworn to before me this 9th day of August, 2012.

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AFFIDAVIT OF ERIN L. MALONEY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Erin L. Maloney, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Erin L. Maloney
Erin L. Maloney

Subscribed and sworn to before me this 9th day of August, 2012.

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AFFIDAVIT OF KEITH MAJORS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Keith Majors, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Keith Majors

Subscribed and sworn to before me this 9th day of August, 2012.

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AFFIDAVIT OF LENA M. MANTLE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Lena M. Mantle, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Lena M Mantle
Lena M. Mantle

Subscribed and sworn to before me this 9th day of August, 2012.

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AFFIDAVIT OF DAVID MURRAY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

David Murray, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

David Murray

David Murray

Subscribed and sworn to before me this 9th day of August, 2012.

D. Suzie Mankin

Notary Public

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AFFIDAVIT OF CONTESSA POOLE-KING

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Contessa Poole-King, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that she has knowledge of the matters set forth in such Report; and that such matters are true to the best of her knowledge and belief.

Contessa Poole-King

Contessa Poole-King

Subscribed and sworn to before me this 9th day of August, 2012.

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AFFIDAVIT OF BRET G. PRENGER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Bret G. Prenger, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Bret G. Prenger
Bret G. Prenger

Subscribed and sworn to before me this 9th day of August, 2012.

D. Suzie Mankin
Notary Public

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Notary Public - Notary Seal
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AFFIDAVIT OF ARTHUR W. RICE, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Arthur W. Rice, PE, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Arthur W. Rice, PE

Arthur W. Rice, PE

Subscribed and sworn to before me this 9th day of August, 2012.

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AFFIDAVIT OF JOHN A. ROGERS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

John A. Rogers, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

John A Rogers

John A. Rogers

Subscribed and sworn to before me this 9th day of August, 2012.

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AFFIDAVIT OF MICHAEL E. TAYLOR

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Michael E. Taylor, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Michael E. Taylor

Michael E. Taylor

Subscribed and sworn to before me this 9th day of August, 2012.

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AFFIDAVIT OF HENRY E. WARREN PHD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Henry E. Warren PhD, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Henry E Warren

Henry E Warren PhD

Subscribed and sworn to before me this 9th day of August, 2012.

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AFFIDAVIT OF CURT WELLS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Curt Wells, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Curt Wells

Curt Wells

Subscribed and sworn to before me this 9th day of August, 2012.

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AFFIDAVIT OF SEOUNG JOUN WON, PHD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Seoung Joun Won, PhD, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report as identified in the individual sections as identified in the Table of Contents of said Report; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Seoung Joun Won

Seoung Joun Won, PhD

Subscribed and sworn to before me this 9th day of August, 2012.

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