MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

REVENUE REQUIREMENT

THE EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2016-0023

Jefferson City, Missouri
March 25, 2016

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

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STAFF REPORT
REVENUE REQUIREMENT
THE EMPIRE DISTRICT ELECTRIC COMPANY
CASE NO. ER-2016-0023

I. Executive Summary

The Staff of the Missouri Public Service Commission ("Staff") has conducted a review of the current The Empire District Electric Company ("EDE", "Empire" or "Company") electric retail customer rates in relation to the question as to whether these rates are "just and reasonable" as required by Missouri statutes. The Case Number for this current rate increase request is ER-2016-0023. Staff conducted their review performing three levels of customer rate analysis. The first level is to determine whether current rates can provide sufficient revenues to recover EDE's prudent cost to provide safe and adequate service. The second level is to determine whether customer class (e.g. residential, commercial, industrial) rates recover the cost to provide these customers electric service. The third level of review is an analysis of the amount of cost recovery designed into certain rate components (e.g. customer charge, commodity charge, block rates, and terms and conditions). This Report will address the development of the comparison of the monies EDE should collect from the electric rates the PSC authorizes to go into effect no later than September 14, 2016, to EDE's cost to provide electric service under current conditions. This study is being performed in conjunction with customer class cost of service and rate design studies that will be filed at a later date. This audit was performed in response to Empire's application to increase its Missouri jurisdictional permanent retail rates by approximately $33.4 million, exclusive of applicable gross receipts, sales, franchise or occupational fees or taxes, filed on October 16, 2015.

The Staff's first level comparison of current revenue to current costs to provide service is based on the final cost of service and billing determinant filings supporting the rates established in Case Number ER-2014-0351. These final costs were based on a **test year** of the twelve months ending April 30, 2014, with the use of an **update period** ending August 31, 2014. In this study, billing determinants, costs and revenues are updated to September 30, 2015, levels.

Impact of Staff's Revenue Requirement on Each Retail Rate Customer Class

The impact of Staff's recommended rate change for each retail rate customer class will be proposed in Staff's class cost of service report and rate design testimony that is to be filed on April 8, 2016.

A. Major Issues

The following are the major differences in traditional revenue requirement that exist between Staff and Empire based on their respective direct filings. A brief explanation of each item follows:

Return on Equity ("ROE") – Staff has recommended a 9.5% to 10.0% reasonable range for ROE for Empire. This issued is addressed in detail in the Section VII of this Report.

Depreciation - Staff conducted a depreciation study of EDE's current authorized depreciation rates. In Staff's review of the depreciation study filed by Empire in this proceeding, Staff found depreciation rate recommendations of zero percent for five accounts on a going-forward basis. Staff recommends the Commission approve the depreciation dates proposed in Appendix 3, Schedule JAR(DEP)-d1 and order EDE to discontinue its practice of changing its rates to zero percent whenever the depreciation reserve equals the related plant in service balance. Staff proposes adjustments to the depreciation reserve in the amount of $3,082,367 to remove the effects of EDE changing its rates to zero percent from any rates established in this case.

With the retirement of Riverton Units 7 and 8, the accumulated depreciation reserves are under recovered by $7.8 million. Depreciation Staff is not recommending an amortization of the unrecovered reserve as requested by Empire. Depreciation Staff is recommending to transfer reserves.

Riverton Combined Cycle Conversion – Empire is in the process of converting its Riverton 12 combustion turbine to a combined cycle unit. The construction of this conversion is scheduled to be completed by June 1, 2016. Empire has included projected construction costs and expenses in its cost of service. Staff has included an estimate of these costs in its cost of service. If the conversion meets its in-service criteria by June 1, 2016, Staff will include all construction costs prudently incurred as of March 31, 2016, in its true-up audit cost of service.

Fuel and Purchased Power – Staff has calculated Empire's Fuel and Purchased Power using its fuel model dispatch to calculate Empire's fuel and purchased power prior to the conversion of the Riverton 12 unit from a combustion turbine to a combined cycle plant. The Riverton Combined Cycle Plant is currently being constructed and is not operational. Staff will update its Fuel and Purchased Power costs during the true-up audit for this case to reflect Empire's level of expense assuming operation of Riverton 12 as a combined cycle plant if the unit is operational at that time.

Income Taxes - ** ____________________ ** Thus Staff has made an adjustment to zero out current income tax expense and transfer the amount to deferred income tax expense.

There are various other issues between Staff and Empire based on their respective direct filings which appear to be of lower dollar magnitude. These issues are discussed in this Report as well.

B. Public Comments

At the time of the filing of Staff's direct testimony, the Commission had received 30 public comments regarding the subject matter of this rate case. Since two of these public comments are duplicates, there are 29 individual comments received at this time. Additional comments are still being received. Schedule KKB-d1 shows the comments that have been received to date. It is expected that the April local public hearings and the later stages of the case will continue to generate additional comments.

C. Regulatory Trackers

The following are tracking mechanisms which the Staff considered in this cost of service study. While continuation of current trackers may not have an immediate direct effect on the EDE's revenue requirement, their ongoing operation will impact future rate cases and future revenue requirements. The Vegetation Management Tracker and the Iatan and Plum Point Operations and Maintenance ("O&M") Tracker were discontinued with the resolution of the previous case, Case No. ER-2014-0351. Staff has calculated the accumulated amounts for these trackers as of the effective date of rates in the last case and is amortizing the balances. While there are now fewer trackers in place for Empire, Staff's position remains that use of trackers can be appropriate under certain circumstances. Staff recommends the use of the following trackers by Empire on an ongoing basis:

Riverton 12 Unit Maintenance Tracker – A tracker was established in the last rate case, Case No. ER-2014-0351, for costs associated with the new maintenance contract with Siemens Instrumentation, Controls and Electrical Group ("Siemens") for the Riverton 12 unit. The tracker base amount of $2.7 million Missouri Jurisdictional was agreed to in the *Non-Unanimous Stipulation and Agreement*. In this current case, Empire is proposing to rebase the Riverton 12 O&M tracker from $2.7 million to $3.9 million based on a new estimated equivalent operating hours ("EOH") calculation. It is Staff's position that the tracker base level remain at $2.7 million as there has not yet been sufficient operational history for this unit in combined cycle operation to determine a more accurate estimate.

Pension and OPEBs Tracker – Staff recommends continuation of the pension and OPEBs trackers that were last authorized for continuance in Empire's previous rate case, Case No. ER- 2014-0351.

Staff Expert/Witness Kimberly K. Bolin

II. Background of EDE

EDE is a Kansas corporation providing retail electrical utility services in Missouri, Kansas, Arkansas, and Oklahoma. As of September 30, 2015, Empire served approximately 169,142 retail electric customers throughout its system of which approximately 150,397 are Missouri customers. EDE provides wholesale electrical service to three municipalities in Missouri and one municipality in Kansas. EDE also provides water utility services in Missouri. EDE is a service company and a holding company. EDE owns and services Empire District Gas Company ("EDG"), an affiliated Missouri natural gas distribution business. EDE also owns and services The Empire District Industries, Inc. ("EDI") an affiliated Missouri non- regulated fiber optic business.

Empire last sought to change its Missouri jurisdictional electric retail rates in Case No. ER-2014-0351. Through its *Order* dated June 24, 2015, in that proceeding, the Commission granted Empire a total net increase in rates of $17,150,000.

On March 16, 2016, Empire filed with the Commission an application along with Liberty Utilities (Central) Co. ("LU Central") and Liberty Sub Corp. authorizing LU Central and Liberty Sub Corp. to acquire all of the common stock of Empire. The case, Case No. EM-2016-0213 is currently pending before the Commission. The outcome of the merger case is not expected to be finalized during the pendency of this case.

Staff Expert/Witness Kimberly K. Bolin

III. Test Year/Update Period/True-Up

The purpose of an update period is to establish a cut-off point as to which major elements of a utility's revenue requirement are to be updated, beyond the test year, for inclusion in Staff's and other parties' direct cases. In contrast, a true-up is a re-audit and update of major elements of a utility's revenue requirement beyond the end of the ordered test year and update period. When ordered, true-ups involve the filing of additional testimony and the scheduling of additional evidentiary hearings by the Commission.

Empire filed its case based upon final costs and billing determinants used to establish current rates in its last rate case, Case No. ER-2014-0351. In that case, the Commission ordered a test year based upon twelve months ending April 30, 2014, with an update period to reflect known and measureable changes through August 31, 2014. The parties have agreed to use the final rate base levels, revenues and expenses (i.e. revenue requirement components), as well as the billing determinants used in Case No. ER-2014-0351, as a starting point for the analysis of Empire's need for a rate change in this case. The billing determinants and other revenue requirement components will be analyzed and updated through September 30, 2015.

The parties have agreed to a true-up of significant items through March 31, 2016, with a Riverton 12 conversion in-service no later than June 1, 2016. Staff has included in Staff's Accounting Schedules an estimate of the impact the addition of this plant will cause on Empire's revenue requirement. Due to the fact that the Riverton 12 conversion is expected not to be in-service as of the end of the true-up period in this case, Staff considers the inclusion of Riverton 12 conversion project costs in rates in this proceeding to be an "out of period adjustment." Therefore, Staff recommends that an "average declining balance" approach be used to calculate the revenue requirement impact of Riverton 12 on rates during the first year it will be in service. To calculate the average declining balance, Staff used the estimated book value as of March 31, 2016, to calculate the associated monthly depreciation expense. Then, the depreciation expense was deducted from the estimated book value per month to derive a monthly depreciated balance for 12 months. Finally, Staff averaged the balance for those twelve months. Staff considers the Riverton 12 project costs to be an out of period adjustment in this proceeding because no costs are eligible to be included in rates unless the project goes in service by June 1, 2016, which is outside the test year, update and true-up periods in this case. There is no actual plant in service balance in existence related to this project as of the March 31, 2016, true-up cut-off date in this case. While Staff is not opposed to inclusion of Riverton 12 costs in rates resulting from this case as an out of period adjustment if the project qualifies for in-service status as of June 1, 2016, Staff's position is that the rate base valuation treatment described above is appropriate given its out of period status. The "Allowance for True-up" estimated value provided on Accounting Schedule 1, Revenue Requirement, is based in part on valuation of the Riverton 12 project costs on an average declining cost basis.

For purposes of the true-up audit, Staff will update the following items through March 31, 2016: plant in service; depreciation reserve, other rate base components (including trackers); payroll expense; payroll-related benefits; fuel and purchased power costs; depreciation and amortization expense; rate case expense; property taxes; related income tax effects; the customer growth annualization for revenues, SPP transmission revenues and expenses, other SPP revenues and expenses, capital structure, and debt costs used in determining the rate of return. This is not an all-inclusive list of items to be updated. Other items might be added to the list to be updated as data becomes available that indicates that their consideration is needed to develop an appropriate matched cost of service analysis.

Staff Expert/Witness: Amanda C. McMellen

IV. Riverton Conversion Project (Construction Audit)

A. Description of Project

Prior to conversion, Riverton Unit 12 was a simple cycle natural gas-fired combustion turbine fully owned by Empire located at the 107-year old Riverton Power Plant in Riverton, Kansas (about thirty minutes west of Joplin, Missouri). When this unit was originally constructed natural gas piping, electrical transmission and the plant layout were designed and built to accommodate its conversion to a combined cycle unit at some point in the future. This construction project incorporates the Riverton Unit 12 combustion turbine as part of a combined cycle unit. "Combined Cycle" refers to the fact that the system uses waste heat from the combustion power cycle to produce steam that is used as the motive force in a steam power cycle. The project requires the addition of a heat recovery steam generator ("HRSG"), a steam turbine generator ("STG"), auxiliary boiler, cooling towers to provide cooling water for the condenser, new control room and control system and other auxiliary plant equipment. The Riverton 12 simple cycle to combined cycle conversion project will add about ** _______________ **, making the Riverton combined cycle a ** ___ ** MW unit upon completion.

Staff Expert/Witness: Erin L. Maloney

B. In-Service Criteria for Riverton 12 CC Unit

The Staff and Empire have agreed on a set of in-service criteria to be used to verify when the Riverton 12 combined cycle ("CC") generating unit is fully operational and used for service and should be considered for inclusion in rate base. These in-service criteria are attached as Schedule ELM-d1 to this report. Staff will review all test records, operating logs, computer data and other documentation provided by the Company to determine if the generating unit successfully meets all of the in-service criteria and is fully operational and used for service when the latest project status and start-up and commissioning reports are made available. Staff will make a recommendation in its final construction audit report prior to the end of the true-up period for this case.

Staff Expert/Witness: Erin L. Maloney

C. Construction Audit of the Riverton 12 CC Unit

As of September 30, 2015, the end of the update period for this case, the Company was in the process of completing the construction of the Riverton Conversion Project / Construction. The parties have agreed to true-up certain significant items of this case through March 31, 2016,

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if the Company meets the Riverton 12 conversion in-service criteria by no later than June 1, 2016. Based upon the expected completion date of this project, Staff is continuing to conduct a construction audit of the new plant and will provide the results of that audit during the true-up phase of this rate case proceeding.

Staff's construction audit and prudence review will include a determination of the appropriate level of construction costs related to the Riverton conversion project for the purpose of setting rates, and provide an independent and objective assessment of the utility's performance as it relates to these specific construction project activities. As part of its construction audit and prudence review, Staff is examining Empire's: (1) entry into agreements to pursue the Riverton Conversion project, (2) Request for Proposals for contractors, (3) Bid Proposals (4) actual expenditures as compared to estimates, and (4) whether the Company's decisions or costs associated with those decisions were (a) inappropriate, (b) unreasonable, (c) excessive, (d) unreasonably or inappropriately allocated, (e) not of benefit to Missouri ratepayers or (f) related to unnecessary facilities. Staff reviewed the Company's decisions considering whether such decisions would result in harm to Empire's ratepayers, in light of the following factors established by Staff:

1. Impact on rate base with related impact on interest cost, expected profit, income taxes;
2. Projected operation and maintenance expense;
3. Projected fuel and consumable-related expense;
4. Projected effect on fuel and purchased-power cost recovery mechanisms;
5. Projected effect on depreciation rates and expense;
6. Projected operational impacts, including plan dispatch ability, dispatch order, or reductions to net generation;
7. Consistency with the utility's Preferred Resource Plan effective at the time the project was undertaken, and as subsequently updated or superseded;
8. Compliance with State and Federal environmental and renewable energy standards and any other applicable State and Federal mandates in effect during the construction of the project;
9. Compliance with settlements or other agreements; and
10. Evaluation of other projects to improve this project.

The Company commissioned a study related to the Clean Water Act, Section 316(b) regulation and Staff is currently evaluating Empire's decision to fully allocate the cost of that study to the capital cost of this project. Staff's final report will provide an independent assessment of Empire's stewardship, performance, and costs as it relates to construction project activities. Staff's final report will also contain analysis regarding the impact of the combined cycle unit on operational and maintenance expense, fuel and consumable-related expense, and the effect on the Company's fuel adjustment clause. Staff continues to review engineering and cost data and will submit a completed audit report when the project is complete.

Staff Expert/Witness: Kimberly K. Bolin, Paul Harrison and Erin L. Maloney

D. Decision to Build Riverton 12 CC Unit

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[1] ** **

[2] ** **

[3] ** **

[4] ** **

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Staff Expert/Witness: Erin L. Maloney

V. Asbury Air Quality Control System ("AQCS")

A. Purpose of Staff's Construction Audit and Prudence Review

In Empire's previous case, Case No. ER-2014-0351, the parties agreed in the *Stipulation and Agreement* to adopt Staff's recommended in-service criteria and found that the Asbury AQCS was fully operational and used for service. However, Staff's construction audit was not complete at that time so the parties agreed that any party to Empire's next rate case (*i.e.,* this case) could argue the book value of the Asbury AQCS. Staff has since completed this audit to determine the appropriate level of construction costs, related to Asbury's AQCS constructed as the Asbury Environmental Retrofit Project ("AERP"), to be used for purposes of setting rates, and to provide an independent and objective assessment of the utility's performance as it relates to these specific construction project activities. As part of its construction audit and prudence review, Staff examined Empire's (1) entry into agreements to pursue the AERP, (2) undertaking of the AERP and (3) continuing with construction of the AERP in light of whether the decisions or costs associated with those decisions were (a) inappropriate, (b) unreasonable, (c) excessive, (d) unreasonably or inappropriately allocated, (e) not of benefit to Missouri ratepayers or (f) related to unnecessary facilities. Staff reviewed the company's decisions considering whether such decisions would result in harm to Empire's ratepayers, in light of the following factors established by Staff:

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1. Impact on rate base;
2. Projected operation and maintenance expense;
3. Projected fuel and consumable-related expense;
4. Projected effect on the Fuel and Purchased-Power Cost Recovery Mechanisms;
5. Projected effect on depreciation rates and expense;
6. Projected operational impacts, including plan dispatch ability, dispatch order, or reductions to net generation;
7. Consistency with the utility's Preferred Resource Plan effective at the time the project was undertaken, and as subsequently updated or superseded;
8. Compliance with State and Federal environmental and renewable energy standards and any other applicable State and Federal mandates in effect during the construction of the project;
9. Compliance with settlements or other agreements; and
10. Evaluation of other projects to improve this project.

B. Risk Assessment

The Staff has determined that the Asbury AQCS costs incurred were prudent, reasonable, appropriate, and constitute a benefit to Missouri ratepayers. The Staff's basis for this determination is a thorough examination of all actual costs.

C. Audit Scope

As part of its audit scope, Staff reviewed the costs and schedule controls utilized by Empire and its project managers in order to familiarize itself with the policies and procedures Empire had in place to control costs and mitigate risks for the Asbury AQCS project. Staff reviewed the following documents during the audit process:

1. Asbury Environmental Retrofit Project monthly reports
2. Key vendor contracts
3. Empire District Electric Board of Director Minutes
4. Work Orders
5. Invoices
6. Change Order Requests
7. Requests for Proposal Letters
8. Internal Procedures and Policies for Empire
9. Alberici Stanley Joint Venture weekly meeting minutes

Staff also visited the construction site and asked questions of Empire personnel during the site visit.

D. Fully Operational and Useful for Service

During Empire's last rate case, Case No. ER-2014-0351, Staff determined that the AQCS improvements at the Asbury plant were completed and the plant met its in-service criteria as of December 2014. AQCS improvements consist of a scrubber, fabric filter, and power activated carbon injection system as part of Empire's plan to comply with Environmental Protection Agency ("EPA") standards.

E. Decision to Construct the AQCS

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F. Bidding Process

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G. Gross Capital Cost and Expenses of the Project and Recommended Cost

When Empire first decided to install the AQCS at Asbury, it began with a budget of **

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Empire had five change orders to the original project budget. The following table provides the reason for each of the change orders and the amount of each change order.

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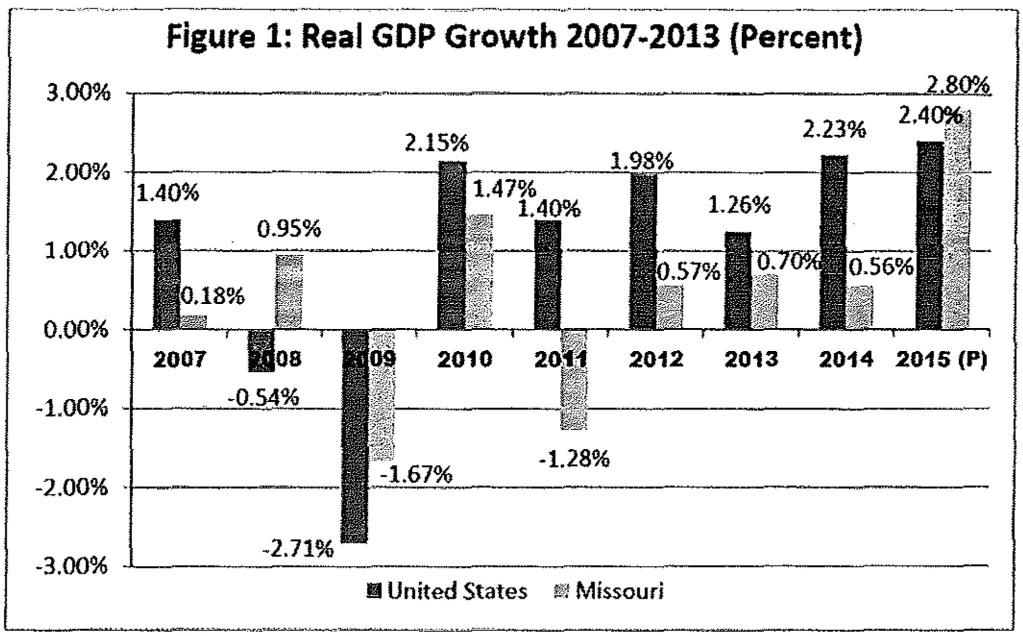
H. Staff Recommendation

Staff is not proposing any adjustments to actual Asbury AQCS Project costs.

Staff Expert/Witness: Kimberly K. Bolin

VI. Economic Considerations

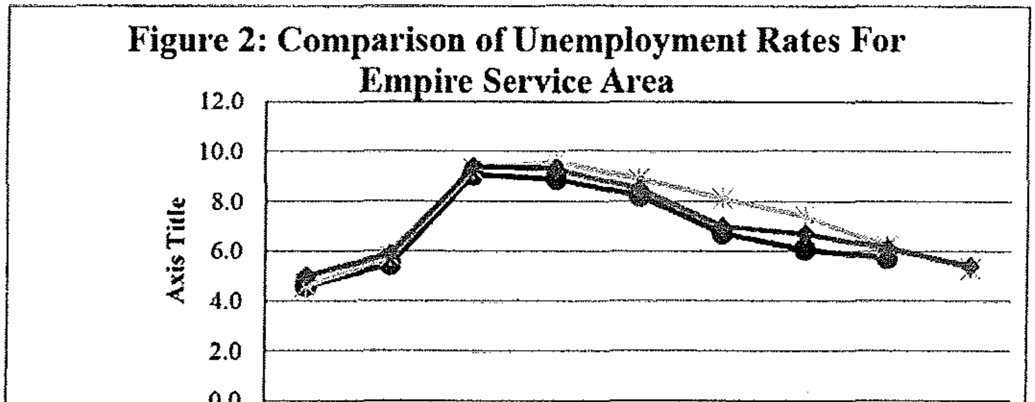
Preliminary 2015 data indicates that Missouri's general economic condition, specifically the counties[6] that compose the service area of Empire, may have finally recovered from the recession of December 2007 to June 2009. Figure 1, below, shows that the real gross domestic product ("GDP") growth of Missouri had been averaging less than one percent (1%) per year since the recession ended, but the preliminary 2015 data shows a robust year-over-year growth rate at 2.80 percent—the largest annual growth rate since 2000.



As seen in Figure 2, below, the annual unemployment levels are approaching the pre-recession levels. The preliminary unemployment rate estimates for 2015 show the Missouri unemployment rate below the 2008 unemployment rate. Preliminary unemployment rate data for Empire's service territory is unavailable. However, since the combined unemployment rate for

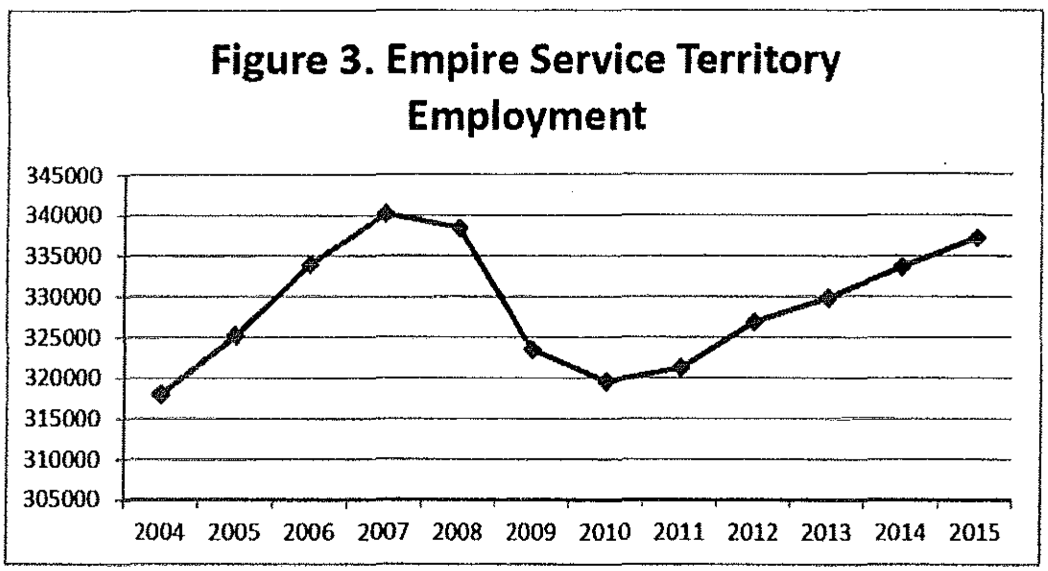
[6] According to Schedule 2 of the minimum filing requirements and the current tariffs, Empire serves a total of 16 counties.

all of the counties that Empire serves tends to be 0.3 to 0.4 percent less than Missouri's unemployment rate, it is reasonable to anticipate a 5.0 to 5.1 percent unemployment rate for Empire's service territory in 2015.



	2007	2008	2009	2010	2011	2012	2013	2014	2015 (P)
Empire	4.6	5.5	9.1	8.9	8.2	6.7	6.1	5.7	
United States	4.6	5.8	9.3	9.6	8.9	8.1	7.4	6.2	5.3
Missouri	5.0	5.9	9.4	9.3	8.5	7.0	6.7	6.1	5.4

The improved employment situation can also be seen in Figure 3. The preliminary numbers for 2015 indicate that employment in Empire's service territory is approaching the 2007 pre-recession peak.



In addition to examining the status of the current economy, economic forecasters also examine economic data that have a history of leading, lagging, or coinciding with changes in the broader economy to anticipate future economic conditions. The current economic outlook from a variety of economic forecasters has softened since Empire's last rate case, No. ER-2014-0351. For instance, the American Institute for Economic Research's ("AIER")[7] most recent version of Business Cycle Conditions (February 2016) shows that 54 percent of the leading indicators are evaluated as expanding, down from 82 percent in December 2014, which Staff reported in Empire's last rate case.[8] In addition, the percentage of expanding coincident indicators fell to 67 percent from 100 percent in December 2014. Under AIER's method, consistent evaluations above 50 percent suggest a low probability of recession over the next six to 12 months. It should be noted that since March 2015, four months have had evaluations at, but not below, 50 percent. Overall, AIER holds the view that while the U.S. is on a sustainable, moderate growth path, "the outlook remains fragile given the strong crosscurrents affecting various parts of the economy."[9] Further, CITI's 2016 outlook released December 1, 2015, estimated a 65 percent chance of a U.S. recession in 2016.[10]

Figure 4 provides a comparison of the increase in average weekly wages for the counties in the Empire service area, Consumer Price Index ("CPI"), Producer Price Index ("PPI"),[11] and Empire electric rates. From 2007 to 2015, the counties in the Empire service area collectively experienced a 17.4 percent increase in average weekly wages. This was about one percent (1%) higher than the overall Missouri compounded increase in average weekly wages of 16.12 percent and slightly higher than the increase in the CPI. During that same time period, electric rates for

[7] American Institute for Economic Research. (16FEB16). "Business Conditions Monthly." https://www.aier.org/bcmoverview2016feb (16FEB16).

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

[9] American Institute for Economic Research. (16FEB16). "Business Conditions Monthly." https://www.aier.org/bcmeconomy2016feb (16FEB16).

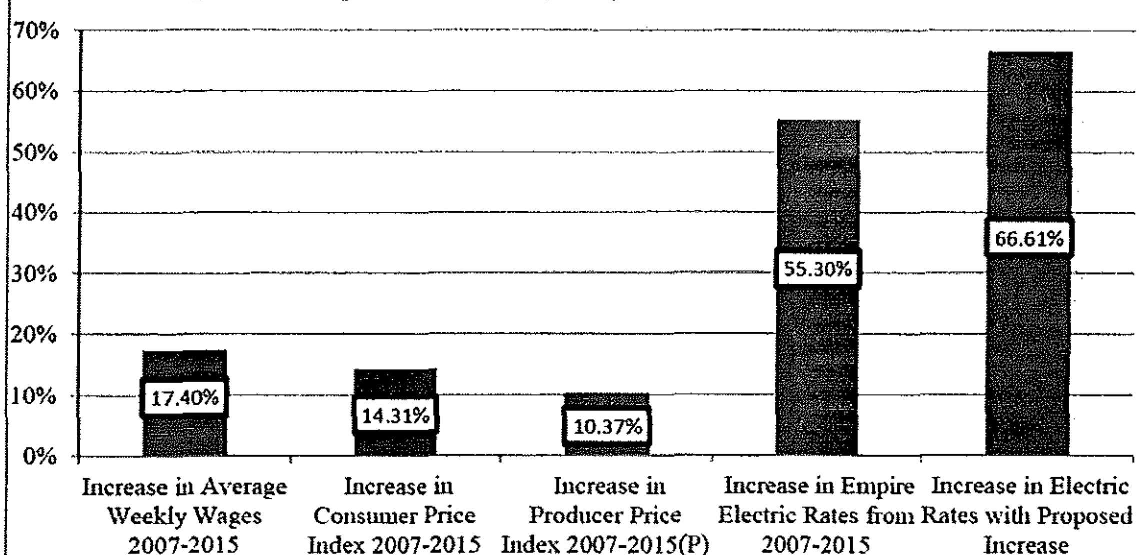
[10] The outlooks are for the U.S. economy in general and may not reflect the outlook in any specific sector.

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

residential customers served by Empire increased, in Case Nos. ER-2006-0315, ER-2008-0093, ER-2010-0130, ER-2011-0004, ER-2012-0345 and ER-2014-0351, a cumulative total of 55.3 percent, which accumulated to a total increase of approximately $161.5 million, shown in Table 1.

Empire has also experienced inflationary pressure illustrated by a 10.37 percent increase in the PPI for industrial commodities from 2007 to 2015.[12] However, the PPI for industrial commodities decreased 7.21 percent from 2014, largely due to the collapse of energy commodity prices. Empire is currently requesting an additional $33.4 million or a 7.28 percent increase in rates. From 2007 to 2015, the increase in average weekly wages for counties in the Empire service area is less than one-third of the increase in electric rates for Empire customers. If Empire receives its requested 7.28 percent increase, the increase in average weekly wages would be just over one-fourth of the increase in electric rates.

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



continued on next page

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

Table 1: Empire Rate Case History 2007 - 2015			
Case Number	Effective Date	Dollar Value	Percent Increase
ER-2006-0315	14-Dec-07	$29,300,000	9.96%
ER-2008-0093	23-Aug-08	$22,040,395	6.70%
ER-2010-0130	10-Sep-10	$46,800,000	13.90%
ER-2011-0004	15-Jun-11	$18,685,000	4.70%
ER-2012-0345	1-Apr-13	$27,500,000	6.85%
ER-2014-0351	26-Jul-15	$17,125,000	3.88%
Total Dollars		$161,450,395	
Total Compounded Increase			55.30%
ER-2016-0023	(Proposed)	$33,397,363	7.28%
Total with Proposed		*$194,847,758*	*66.61%*

Lastly, according to the 2009 Residential Energy Consumption Survey,[13] the most recent survey available by the U.S. Department of Energy, Energy Information Administration, Missouri households consume about 12% more energy than the U.S. average. However, the historically lower residential electricity prices result in the average Missouri household paying slightly less for energy than the national average. Overall, the median Missouri household spends about 2.37% of its income on electricity. For households that were identified as being at or below the 150% poverty line, the median increased to 7.68%.

Staff Expert/Witness: Michael L. Stahlman

[13] U.S. Energy Information Administration. (2014). "Residential Energy Consumption Survey." U.S. Department of Energy, www.eia.gov/consumption/residential/index.cfm (18NOV14).

VII. Rate of Return

A. Introduction

An essential ingredient of the cost-of-service ratemaking formula is the rate of return ("ROR"), which is usually premised on the goal of allowing a utility the opportunity to recover the costs required to secure debt and equity financing. If the allowed ROR is based on the costs to acquire capital, then it is synonymous with the utility's weighted average cost of capital ("WACC"), which is calculated by multiplying each component ratio of the appropriate capital structure by its cost and then summing the results. While the proportion and cost of most components of the capital structure are a matter of record, the cost of common equity must be determined through expert analysis.

Staff's expert financial analyst, Shana Griffin, estimated Empire's cost of common equity by applying well-respected and widely-used methodologies to data derived from a carefully-assembled group of comparable companies, also referred to as the proxy group. Staff then compared that cost of common equity to Staff's recent estimates of the cost of common equity estimates for the electric utility industry in the recent Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri"), Empire and Kansas City Power & Light ("KCPL") rate cases, as well as an update to the cost of common equity for the same refined electric utility proxy group,[14] to provide the Commission with a quantitative estimate of a fair and reasonable allowed ROE for Empire in light of the Commission's recent allowed ROE determinations in the Ameren Missouri and KCPL rate cases.[15]

Staff's multi-stage Discounted Cash Flow ("DCF") analysis shows that the regulated electric utility industry's cost of equity, as measured by Staff's selected proxy group and measured by Staff's refined proxy group from the 2014 electric rate cases, has declined by approximately 20 to 25 basis points since the Ameren Missouri rate case, increased by about 10 basis points since the Empire rate case and 25 basis points since the KCPL rate case. (*see* Schedule 15). Staff's comparison assumes the use of the same proxy group and same

[14] Minus Southern Company because it recently announced a proposed major acquisition of AGL Resources, which can distort its stock price.

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

perpetual growth rates for both periods. Staff notes that if it were to use GDP growth rates as some witnesses advocate, it would imply a cost of equity that is 25 basis points lower for the updated analysis. As Staff emphasized in its testimony in the current Missouri American Water Company rate case, Case No. WR-2015-0301, Staff's quantification of a 25 to 75-basis point decline in the electric utility industry's Cost of Equity ("COE") in 2014 was benchmarked off of its initial analysis in the Ameren Missouri 2014 electric rate case, Case No. ER-2014-0258. As can be seen from the information on Schedule 15, Staff's updated analysis through the Empire and KCPL rate cases supported an even greater decline in the COE as long-term interest rates declined considerably through the end of 2014 and into early 2015, which drove up electric utility price-to-earnings ("P/E") ratios and drove down electric utility dividend yields. Although Staff believed its updated analysis that incorporated these higher valuation levels supported approximately a 100-basis point decline in the electric utility industry's COE, Staff continued to recommend a more conservative reduction of 25 to 75 basis points. The Commission ultimately decided to authorize ROEs that were approximately 25 basis points below Ameren Missouri's and KCPL's previously authorized ROEs of 9.80% and 9.70%, respectively.

As discussed, Staff's updated analysis in this case shows a lower COE than when Staff performed its analysis in the Ameren Missouri rate case. If these lower COE indications continue for the next few months, then this would support even lower allowed ROEs than those that the Commission authorized last year. However, due to mixed signals between utility debt markets and equity markets, Staff believes the benchmark the Commission set in 2015 is still a reasonable starting point for a fair allowed ROE. For purposes of setting Empire's allowed ROE, the Commission must consider Empire's slightly higher risk level than its Missouri peers. Based on 'A' rated and 'BBB'/'Baa' rated bond yield spreads data Staff reviewed from Value Line, Moody's Mergent Bond Record and the Financial Industry Regulatory Authority ("FINRA"), a 25-basis point risk premium would be appropriate for Empire's allowed ROE. Staff recommends the Commission set Empire's allowed ROR based on an allowed ROE of 9.50% to 10.00%, mid-point 9.75% (as of the September 30, 2015, update period). The details of the capital structure and the return components are detailed in the following table:

Capital Component	Percentage of Capital	Embedded Cost	Allowed Rate of Return Using Common Equity Return of: 9.50%	9.75%	10.00%
Common Stock Equity	48.73%	----	4.63%	4.75%	4.87%
Long-Term Debt	51.27%	5.33%	2.73%	2.73%	2.73%
Total	100.00%		7.36%	7.49%	7.61%

The details of Staff's analysis and recommendations are presented in Schedules 1-17 in Appendix 2. Staff's workpapers will be provided to the parties at the time of filing Staff's Cost of Service Report. Staff will make any source documents of specific interest available upon the request of any party to this case or upon the Commission's request.

B. Analytical Parameters

The determination of a fair rate of return is guided by principles of economic and financial theory and by certain minimum Constitutional standards. Investor-owned public utilities such as Empire 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.[16] In ***Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia***, the Court stated:[17]

> 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

[16] *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).

[17] 262 U.S. at 692-693, 43 S.Ct. at 679, 67 L.Ed. at 1176, 1182-83

> 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:[18]

> '[R]egulation does not insure that the business shall produce net revenues.' But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

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

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

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

[18] 320 U.S. at 603, 64 S.Ct. at 288, 88 L.Ed. at 345.

The methodologies of financial analysis have advanced greatly since the ***Bluefield*** and ***Hope*** decisions.[19] 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 Empire's shareholders may expect is equal to that required for comparable-risk utility companies.

Financial theory holds that the company-specific DCF method satisfies the constitutional principles inherent in estimating a return consistent with those of companies of comparable risk;[20] 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 Empire.

In this case, Staff has applied this comparable company approach through the use of both the DCF method and the Capital Asset Pricing Model ("CAPM"). Properly used and applied in appropriate circumstances, both the DCF and the CAPM methodologies can provide accurate estimates of a utility's cost of equity. Because it is well-accepted economic theory that a company that earns its cost of capital will be able to attract capital and maintain its financial integrity, Staff believes that authorizing an *allowed* return on common equity based on the *cost* of common equity is consistent with the principles set forth in ***Hope*** and ***Bluefield***. However, as Staff will discuss extensively throughout this section of the report, Staff believes it is common practice for commissions to allow returns on equity that are higher than the costs of equity for utilities. Consequently, Staff's recommended allowed ROE is higher than Staff's estimate of Empire's cost of equity.

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

[20] 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*.

Because the Commission recently authorized ROEs of 9.53% for Ameren Missouri, and 9.50% for KCPL based on recent economic and capital market conditions, Staff believes it can best serve the Commission by providing it an estimate of the relative change in regulated electric utilities' cost of equity in general, since these last rate cases, Case Nos. ER-2014-0258, and ER-2014-0370 ("the 2014 rate cases"). Although the implied cost of equity based on data through February 2016 is lower than when Staff provided its recommendation in the Ameren Missouri rate case, it is higher than when Staff performed its analysis in the Empire and KCPL rate cases. Additionally, unlike at the end of 2014 and early 2015, utility company bond yields have not declined as significantly in recent months. Consequently, Staff recommends the Commission allow Empire an ROE in a range of 9.50 to 10.00 percent with a point estimate of 9.75 percent. Staff's recommended ROE and ROE range for Empire is higher than the ROEs that were recently authorized in the 2014 rate cases due to Empire's lower credit rating, which is based on the business and financial risks of Empire's regulated utility operations. Staff added 25 basis points due to Empire's lower credit rating, which is based on the business and financial risks of Empire's regulated utility operations. Ameren and KCPL have corporate credit ratings of 'BBB+' while Empire has a corporate credit rating of 'BBB'. The spread between 'A' and 'BBB'/'Baa' rated utility bonds have averaged 45 basis points over the long term.[21] This spread would normally suggest a 15-basis point risk premium is acceptable for a company rated one notch lower (45/3 = 15). Value Line data shows approximately a 53-basis point spread between 'A' rated and 'BBB'/'Baa' rated bond yields for the twelve weeks ended February 17, 2016.[22] Staff noticed that recent Mergent Bond Record data showed spreads between 'A' rated and 'BBB'/'Baa' rated utility bonds to be equal to over 100 basis points. Therefore, Staff obtained the constituent list of the specific bonds that are used in the calculation of Mergent's utility bond yield averages in order to study why the spreads have recently more than doubled as compared to the historical average spread. Staff could not verify the methodology used by Mergent to calculate the bond yield averages. However, it seems that the 'BBB'/'Baa'-rated bond yield average is skewed higher due to the energy bonds included in the averages. Using data from FINRA, for the twelve weeks ended March 14, 2016, Staff calculated what the average 'A' rated

[21] Mergent Bond Record data shows from January 1996 to January 2016 the average spread between 'A' rated and 'BBB'/'Baa' rated utility bond yields has averaged 45 basis points.

[22] Value Line Selection & Opinions December 11, 2015 through February 26, 2016, except for the February 5, 2016, Selection & Opinion because it was unavailable to Staff at the time of testimony.

and 'BBB'/'Baa' rated utility bond yields would be using Mergent's constituent list excluding the energy companies. Staff found that the average spread would be approximately 65 basis points when the energy companies are excluded. This spread would suggest approximately a 22-basis point risk premium is acceptable for a company rated one notch lower (65/3 = 21.67). Therefore, because of the recent increase in spreads between 'A' and 'BBB'/'Baa' rated utility bonds, Staff recommends a 25-basis point adjustment.

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

Although economic growth was positive in 2015, this growth has been fairly low. Real GDP increased by 0.6 percent in the first quarter, 3.9 percent in the second quarter, 2.0 percent in the third quarter and 1.0 percent in the fourth quarter. Real GDP increased 2.4 percent in 2015. The Commerce Department revised its fourth quarter GDP estimate up from an earlier estimate of 0.7 percent.[23] As of December 2015, the Federal Reserve Board ("Fed") Members and the Federal Reserve Bank Presidents projected real GDP would grow between 2.3 and 2.5 percent in 2016, 2.0 and 2.3 percent in 2017, and 1.8 and 2.2 percent in 2018. The longer run projections for real GDP growth were between 1.8 and 2.2 percent.[24]

Although the Fed increased the Fed Funds rate at its December 15-16 meeting, it appears that the Fed will need to be very careful about how quickly it increases the Fed Funds rate due to the fragile economy. Although some believed that an increase in the Fed Funds rate would cause an increase in long-term rates, this did not happen. Long-term rates typically are much more a function of the market and economic forces rather than monetary policy influence. In fact, many market participants believed long-term rates would increase when the Fed terminated its

[23] http://www.bea.gov/national/index.htm#gdp. "Real" GDP is adjusted to reflect inflation.

[24] http://www.federalreserve.gov/monetarypolicy/files/fomcprojtabl20151216.pdf.

bond-buying program in October 2014. However, market forces driven by the impact of falling energy prices, slowing growth in China, economic, financial concerns in European countries, and lowered economic growth outlooks for United States, caused a decline in long-term rates after the Fed terminated its bond-buying program. This caused utility stock prices to increase dramatically at the end of 2014 and into early 2015. Going forward, one of the key areas of interest for the markets in general, but utilities in particular, is whether an increase in the Fed Funds rate will cause an increase in financing costs. The answer has been *yes* for short-term financing instruments, but no for long-term financing instruments.

A recent *WSJ* article[25] stated:

> The risks to growth, and hiring now don't look so threatening, in part because financial conditions have improved. Stocks have recovered some lost ground after falling in January and early February. Meantime, long-term interest rates dropped, in part because investors have come to see the Fed keeping rates lower than previously expected.

Information released from the Federal Open Market Committee ("FOMC") meeting held on January 27, 2016, shares the FOMC's intention regarding any future changes in the Fed Funds Rate. The following excerpt from the FOMC's press release provides direct comments from the FOMC regarding its views:

> ...Given the economic outlook, the Committee decided to maintain the target range for the federal funds rate at 1/4 to 1/2 percent. The stance of monetary policy remains accommodative, thereby supporting further improvement in labor market conditions and a return to 2 percent inflation.
>
> In determining the timing and size of future adjustments to the target range for the federal funds rate, the Committee will assess realized and expected economic conditions relative to its objectives of maximum employment and 2 percent inflation. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments. In light of the current shortfall of inflation from 2 percent, the Committee will carefully monitor actual and expected progress toward its inflation goal. The Committee expects that economic conditions will evolve in a manner that will warrant only gradual increases in the federal funds rate; the federal funds rate is likely to remain, for some time, below levels that are expected to prevail

[25] Jon Hilsenrath, "Fed Seen Emphasizing Flexibility," *Wall Street Journal*, p. A2, March 9, 2016.

> in the longer run. However, the actual path of the federal funds rate will depend on the economic outlook as informed by incoming data... [26]

The Fed continues to target a 2-percent inflation rate. The economic outlook will determine how the Fed chooses to increase the federal funds rate, but we are likely to see only gradual increases in the federal funds rate.

2. Capital Market Conditions

a. Utility Debt Markets

Utility debt markets indicate a slightly higher cost-of-capital environment than that which existed when the Commission determined an allowed ROE of approximately 9.5% was fair for KCPL and Ameren Missouri. The average utility bond yields, as reported in the Mergent Bond Record, at the time Staff recommended the Commission lower Ameren Missouri's allowed ROE by 25 to 75 basis points, were approximately 4.3%. Average utility bond yields declined to a recent historical low of 3.83% in January 2015. Since January 2015, average utility bond yields have been increasing. At approximately the time the hearings in the KCPL rate case began, average utility bond yields were slightly higher than they were when Staff performed its analysis in the Ameren Missouri rate case. The average utility bond yield for the last three months through January 2016 was approximately 4.68%, which is approximately 40 basis points higher than when Staff recommended the Commission reduce Ameren Missouri's allowed ROE by 25 to 75 basis points.

Although the average utility bond yields indicate an increase in the cost of capital, the utility bond yield data, broken down by category, indicate that the increase in the cost of capital is much more pronounced for utilities that have a weaker investment grade credit rating, *i.e.*, a 'BBB' rating rather than an 'A' rating. Schedule 4-5 shows the average yields on 'A' rated utility bonds versus 'BBB'/'Baa' rated utility bonds since January 1, 2014. Typically the spread between 'A' rated utility bonds and 'BBB'/'Baa' rated utility bonds is 45 basis points over the long-term. However, since the time Staff did its analysis in the Ameren Missouri rate case, this spread has more than doubled to over 100 basis points.

Although the spread between 'BBB'/'Baa'-rated utility bond and 'A'-rated utility bonds published in the Mergent Bond Record seemed consistent with Staff's understanding of issues

[26] Federal Reserve Press Release January 27, 2016.

causing lower grade bonds to have a much higher Yield to Maturity ("YTM"), the spread was much higher than what seemed to be reasonable for fairly stable utility bonds, especially considering the mixed message of increases in utility stock prices, but declines in utility bond prices, at least implied in the Mergent Bond Record. Staff also understood that the energy sector, which includes energy pipeline operators and merchant generation operators, has been experiencing significant volatility in capital market prices. Many of these energy companies are often broadly classified as "utilities" for purposes of various stock and bond indices.

Consequently, Staff pursued additional information from Mergent Bond Record as to the underlying bonds that make up the current Moody's public utility bond averages that are used in Mergent Bond Record. The information provided by Mergent showed that energy pipeline companies with significant exposure to the commodity price volatility were classified as "utilities" and were still rated 'Baa' (Moody's equivalent of Standard & Poors' ("S&P") 'BBB' rating). A few examples of the energy companies' bonds that are included in the Moody's 'Baa' public utility bond yield index are: El Paso Pipeline Partners, Energy Transfer Partners LP, Enlink Midstream Partners LP, Kinder Morgan Energy Partners, and Williams Partners LP. It has been fairly widely recognized in the financial community that these companies' security prices have been very volatile and declined significantly. For example, El Paso Pipeline Partners' bond[27] has traded at YTM's of around 7% during February 2016; Energy Transfer Partners LP's bond[28] has traded at YTM's of around 8% during February 2016; Williams Partners LP's bond[29] has traded at YTM's of around 8.5% during February 2016; and Enlink Midstream Partners LP's bond[30] has traded at YTM's close to 11% around February 24, 2016 (this is the highest YTM of the bonds in the index).

The energy company bonds in the Moody's 'BBB'/'Baa' rated "utility" index make up 7 of the 18 bonds in the index. Staff requested Mergent provide information on the methodology it uses to calculate its utility bond yield averages, but Mergent considered this information to be proprietary. However, removing these energy related "utility" bonds from the index would cause

[27] CUSIP: 28370TAF6.

[28] CUSIP: 29273RAZ2.

[29] CUSIP: 96950FAN4.

[30] CUSIP: 29336UAC1.

the average utility bond yield average to decrease since the rest of the bonds in the index trade in the 4.5% to 5.5% range,[31] which is more typical of investment grade regulated utility bonds.

The average 'A' rated utility bond yield at the time Staff performed its cost of capital analysis in the Ameren Missouri rate case was about 4.15%,[32] whereas the average 'A' rated utility bond yield for the three months through January 2016 was 4.34%, an increase of approximately 20 basis points. The average 'BBB'/'Baa' rated utility bond yield at the time Staff performed its cost of capital analysis in the Ameren Missouri case was approximately 4.70%,[33] whereas the average 'BBB'/'Baa' rated utility bond yield for the three months through January 2016 was 5.54%, an increase of 84 basis points. Although Staff could not verify the methodology used by Mergent to calculate the bond yield averages, it seems that the 'BBB'/'Baa'-rated bond yield average is skewed higher due to the energy bonds included in the averages. For the most recent 3 months through January 2016, the average spread between 30-year T-bonds (2.95 %) and average utility bond yields (4.68 %) was 173 basis points. For the three months ended October 2014, the average spread between 30-year T-bonds (3.17%) and average utility bond yields (4.31%)[34] was 114 basis points. The spread has increased by 59 basis points since the three months ended October 2014. This is explained by the increase in utility bond yields and the decline in 30-year T-bonds. (*See* Schedules 4-3 and 4-4).

b. Utility Equity Markets

For the twelve months ending December 31, 2015, the total return on the Dow Jones Industrial Average ("DJIA") was .2%, the total return on the Standard & Poor's 500 ("S&P 500") was 1.4%, and the total return on the Edison Electric Institute ("EEI") Index of electric utilities was -3.9%.[35] EEI's Stock Performance Q4 2015 Financial Update stated the following:

> The EEI Index gained 1.6% in Q4 while the broad markets reversed Q3 losses and gained 7% and 8%. Rising interest rates in the year's first half and weak natural gas prices during the year led

[31] Data from FINRA from December 21, 2015 through March 14, 2016.

[32] Average monthly yield for August, September and October 2014.

[33] Average monthly yield for August, September and October 2014.

[34] Mergent Bond Record.

[35] EEI Stock Performance 2015 Q4 Financial Update.

to a -3.9% full-year return for the EEI Index, the first negative return since 2008.

The share prices of regulated utilities continued to be supported through 2015 by low interest rates and sturdy dividend yields (about 4% for the industry as a whole).

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

I. Index Comparison (% Return)

Index	2009	2010	2011	2012	2013	2014	2015
EEI Index	10.7	7.0	20.0	2.1	13.0	28.9	-3.9
Dow Jones Inds.	22.7	14.1	8.4	10.2	29.6	10.0	0.2
S&P 500	26.5	15.1	2.1	16.0	32.4	13.7	1.4
Nasdaq Comp.^	43.9	16.9	-1.8	15.9	38.3	13.4	5.7

Calendar year returns shown for all periods, except where noted.
^Price gain/loss only. Other indices show total return.
Source: EEI Finance Department

EEI Index returns during 2015 embodied the larger pattern seen in Table 1 since the 2008/2009 financial crisis, as industry business models have migrated to an increasingly regulated emphasis. The industry has generated consistent positive returns but has lagged the broader markets when markets post strong gains, which in turn have been sparked both by slow but steady U.S. economic growth and corporate profit gains and by the willingness of the Federal Reserve to bolster markets with historically unprecedented monetary support in the form of three rounds of quantitative easing and near-zero short-term interest rates. While the Fed did raise short-term interest rates in December 2015 for the first time since 2006 (from zero to a range of 0.25% to 0.50%), **this hardly effects longer-term yields**, which remain at historically low levels and are influenced more by the level of inflation and economic strength than by the Fed's short-term rate policy. (emphasis added)

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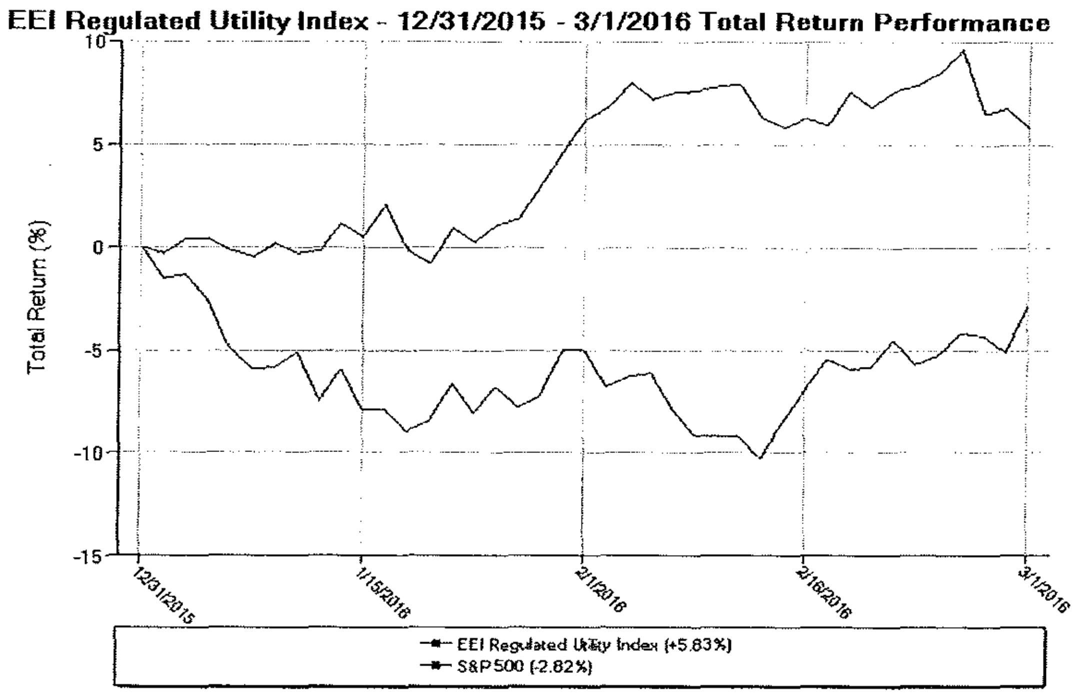
So far in 2016 the EEI Regulated Utility Index has outperformed the S&P 500:



As Staff explained in its testimonies in the 2014 electric utility rate cases testimonies and as confirmed by EEI's commentary, utility stock returns are highly correlated to changes in long-term yields. This proved to be the case during the fourth quarter of 2014 and early 2015. It is also proving to be the case since the beginning of 2016 as shown in the chart above. The increase in utility stock prices causes declines in dividend yields and increases in P/E ratios. As you can see in the charts below, the dividend yields have decreased for the 2014 refined electric proxy group since the beginning of 2016 and the P/E ratios have increased, implying a lower COE.

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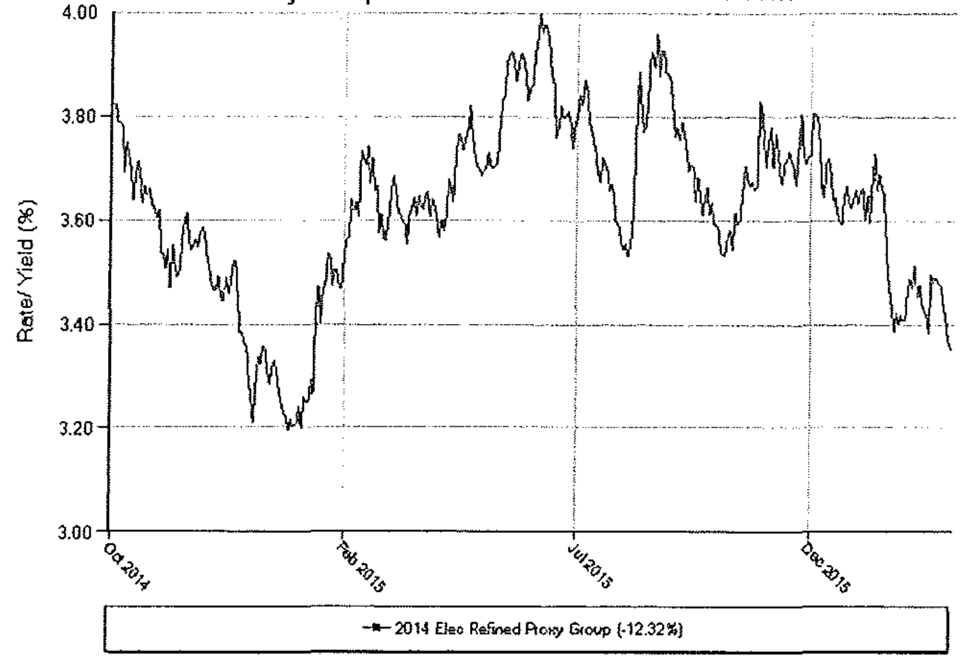
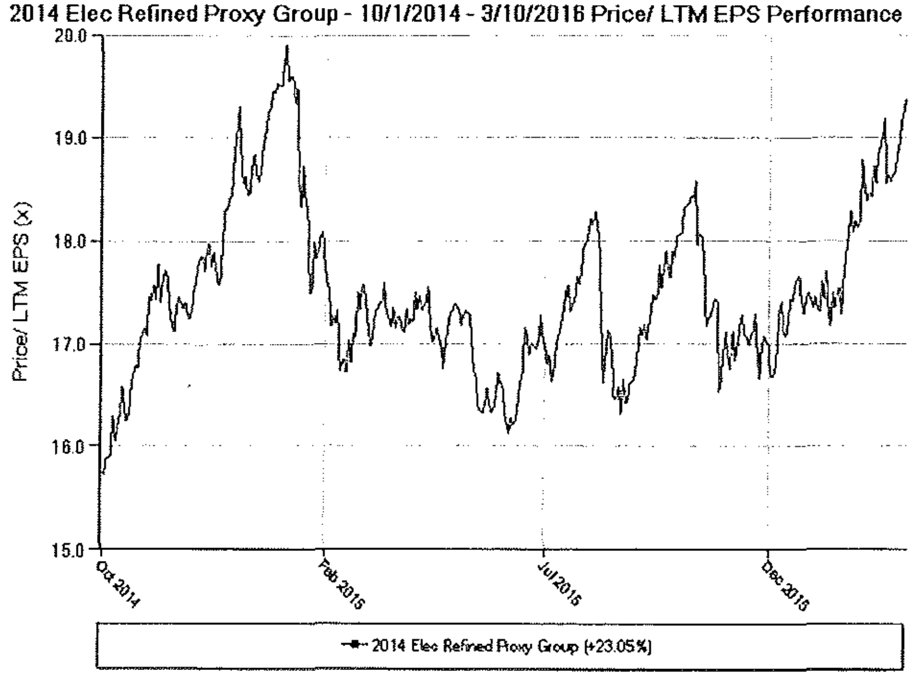
2014 Elec Refined Proxy Group - 10/1/2014 - 3/10/2016 Rate/ Yield Performance



2014 Elec Refined Proxy Group - 10/1/2014 - 3/10/2016 Price/ LTM EPS Performance



In the fall of 2014 to early 2015, it was clear that higher utility P/E ratios were being driven by the decline in interest rates, which made it very convincing that the cost of equity had declined. The other factor that often explains an increase in valuation ratios is a higher expected growth rate in one period as compared to another. The 2014 electric proxy group's FactSet long term projected Earnings Per Share ("EPS") growth rate was approximately 5.69% at the time of the 2014 rate cases and for this case the same proxy group's FactSet long term projected EPS growth rate is 5.56%. Considering the fact that P/E ratios have increased since the fall of 2014 and this is not due to an increase in expected long-term growth, this certainly implies that if anything, the COE for electric utilities may be a little lower since the Commission ordered an ROE of 9.50% for the 2014 cases. Therefore, an allowed ROE consistent with the Commission's decisions in 2015 based on 2014 is still fair and reasonable.

D. Empire's Operations

The following excerpt from Empire's Form 10-K filing with the United States Securities and Exchange Commission ("SEC") for the year ended December 31, 2015, provides a good description of Empire's current business operations:

> We operate our businesses as three segments: electric, gas and other. The Empire District Electric Company (EDE), a Kansas corporation organized in 1909, is an operating public utility engaged in the generation, purchase, transmission, distribution and sale of electricity in parts of Missouri, Kansas, Oklahoma and Arkansas. As part of our electric segment, we also provide water service to three towns in Missouri. The Empire District Gas Company (EDG) is our wholly owned subsidiary engaged in the distribution of natural gas in Missouri. Our other segment consists of our fiber optics business.
>
> Our gross operating revenues in 2015 were derived as follows:

Electric segment sales*		91.7%
On-system revenues	86.6%	
SPP IM revenues	2.5	
Other revenues	2.3	
Gas segment sales		6.9
Other segment sales		1.4

> *Sales from our electric segment include 0.5% from the sale of water.
>
> On-system electric revenues consist of residential, commercial, industrial, wholesale on-system and other (which includes street lighting, other public authorities and interdepartmental usage).

> The territory served by our electric operations embraces an area of about 10,000 square miles, located principally in southwestern Missouri, and also includes smaller areas in southeastern Kansas, northeastern Oklahoma and northwestern Arkansas. The principal economic activities of these areas include light industry, agriculture and tourism. As of December 31, 2015, our electric operations served approximately 170,000 customers.
>
> Our retail electric revenues for 2015 by jurisdiction were derived as follows:
>
> | | |
> |---|---|
> | Missouri | 89.0% |
> | Kansas | 4.8 |
> | Oklahoma | 2.8 |
> | Arkansas | 3.4 |
>
> We supply electric service at retail to 119 incorporated communities as of December 31, 2015, and to various unincorporated areas and at wholesale to four municipally owned distribution systems. The largest urban area we serve is the city of Joplin Missouri, and its immediate vicinity, with a population of approximately 160,000.

E. Empire's Credit Ratings

Empire is currently rated by Moody's and S&P. It is important to understand the current credit standing of Empire, as these ratings influence investors' views of the risk associated with investing in Empire.

Empire's Moody's corporate credit rating is 'Baa1' and its S&P corporate credit rating is 'BBB.'[36] The following is an excerpt from S&P's February 10, 2016, credit-rating report on Empire, discussing S&P's rationale for revising their outlook on Empire to "negative" and affirming their ratings:

> We base the negative outlook on Empire's announcement that it has entered into an agreement to be acquired by Algonquin Power & Utilities Corp. When the transaction closes, we would view Empire as a core subsidiary of Algonquin, leading to an issuer credit rating for Empire that is aligned with that of Algonquin. We base this assessment on the following factors:
>
> - We project that Empire will form a meaningful part of the merged entity, contributing about 40% of Algonquin's EBITDA.

[36] Empire's SEC Form 10-K filing for the year ended December 31, 2015, p.5.

> •Empire operates in lines of business that are integral to the overall group strategy (regulated utility operations).
>
> •We expect Algonquin's management will be strongly committed to Empire given Algonquin's emphasis on maintaining the size and scope of its regulated utility operations relative to nonutility operations.
>
> •Empire will enhance Algonquin's presence in common service territories, especially Missouri, facilitating growth and cost-reduction opportunities.

Because of our view of Empire's core group status, the negative outlook on Empire is in line with the negative outlook on Algonquin, which reflects the risk of weaker near-term credit measures associated with the transaction's timing and financing.

The ratings on Empire are based on the company's strong business and significant financial risk profiles.

We assess Empire District's business risk profile as strong, reflecting the company's historically effective management of regulatory risk, limited service territory that lacks scale and regulatory and operating diversity, and efficient operations. Although the regulatory framework has been somewhat challenging in the past, especially in terms of rate-case lag that affects the company's ability to earn its authorized return, Empire has nonetheless endeavored to reach constructive regulatory outcomes, thus supporting its overall credit profile.

F. Algonquin's Proposed Acquisition of Empire

At this time, Staff does not know how Algonquin plans to structure the acquisition of Empire and how it will finance its operations if it is allowed to acquire Empire. However, the proposed Algonquin acquisition of Empire has not impacted Staff's recommended ROR in this case. Empire's S&P credit rating is on a "negative" outlook due to the proposed acquisition. However, the embedded cost of debt is not impacted because this debt was issued prior to the announcement of the proposed acquisition. Staff used the actual, consolidated capital structure of Empire as of September 30, 2015, as the basis for its capital structure recommendation. Empire's capital structure was not impacted by the announcement of the proposed acquisition as of that date. Staff's recommended allowed ROE has not been influenced by the announcement of the proposed acquisition because Empire is not included in Staff's current proxy group or the 2014 refined proxy group.

Although Staff's ROR recommendation in this case is not impacted by Algonquin's proposed acquisition of Empire, Staff notes that Algonquin is proposing to pay a significant premium for Empire's stock. This significant premium is consistent with premiums proposed in other recently announced transactions. It is widely recognized in the investment community that these larger premiums are being driven by higher valuation levels caused by the low cost of capital environment. Staff urges the Commission to take this into consideration when evaluating the credibility of the various witnesses' cost of equity estimates.

G. 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 (3) an evaluation of a fair and reasonable allowed ROE in light of the Commission's recent decisions in the Ameren Missouri and KCPL rate cases.

1. Capital Structure

Schedule 5 presents Empire's historical capital structures in dollar terms and percentage terms for the years 2011 through 2015.

Staff used the actual, consolidated capital structure of Empire as of September 30, 2015, as the basis for its capital structure recommendation. Schedule 7 presents Empire's capital structure and associated capital ratios. Staff's resulting ratemaking capital structure recommendation consists of 48.73 percent common equity and 51.27 percent long-term debt.

Staff should also note that the recommended ratemaking capital structure does not contain short-term debt. This is not because Empire does not issue short-term debt for purposes of funding its operations. Staff did not include Empire's short-term debt in the capital structure because for the twelve months ending September 30, 2015, Empire's average Construction Work in Progress ("CWIP") balance exceeded its short-term debt balance. Therefore, it is assumed that the short-term debt was used to fund CWIP.

2. Embedded Cost of Debt

Staff's embedded cost of long-term debt of 5.33 percent is based on information provided by Empire in response to Staff Data Request Nos. 0089 and 0090. Staff's embedded cost of long-term debt is slightly lower than that provided by Empire because Staff proposes to disallow the remaining unamortized expense balance of approximately $1,371,065 associated with Empire's $2.5 million of debt expenses incurred to amend its mortgage bond indenture in order to provide additional flexibility to pay its dividend. Staff subtracted this amount from Empire's cost of debt calculation for the period ending September 30, 2015. Staff has consistently proposed this disallowance in Empire's past rate cases as well. Staff provides the underlying details of its embedded cost of debt estimate in Schedule 6.

3. Cost of Common Equity

Staff estimated Empire's cost of common equity through a comparable company cost-of-equity analysis of a proxy group 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

The ultimate goal of selecting a proxy group is to select companies whose operations are confined as much as possible to regulated utility operations ("pure-play regulated utilities"/ "pure-play") with a majority of the regulated utility operations being that of the electric utility sector.

Starting with 66 market-traded companies classified as power companies by SNL Financial, Staff applied a number of criteria to develop a proxy group comparable in risk to Empire's regulated electric utility operations (*see* Schedule 8). Staff's criteria are designed to capture companies with primarily regulated electric operations (which means the companies' operations may have other regulated operations, such as gas distribution), and whose electric utility operations contain a significant amount of generation assets. Staff's criteria accomplished this objective. Staff will show the results of the current proxy group and the 2014 refined proxy group in each of its schedules. Staff's criteria are as follows:[37]

[37] Staff used 2015 data from SNL if it was available, otherwise Staff used 2014 SNL data.

1. Classified as a power company by SNL (66 companies);
2. Publicly-traded stock (one company eliminated, 66 remaining);
3. Followed by EEI and classified by EEI as a regulated utility (33 companies eliminated, 33 remaining);
4. At least 50% of plant from electric utility operations (3 companies eliminated, 30 remaining);
5. At least 25% of electric plant from generation (5 companies eliminated, 25 remaining);
6. At least 80% of income from regulated utility operations (1 company eliminated, 24 remaining);
7. No reduced dividend since 2013 (0 companies eliminated, 24 remaining);
8. At least investment grade credit rating (0 companies eliminated, 24 remaining);
9. At least 2 equity analysts providing long-term growth projections in the last 90 days (5 companies eliminated, 19 remaining);
10. No significant merger or acquisition announced recently (4 companies eliminated, 15 remaining).

The resulting final group of 15 publicly-traded electric utility companies ("the comparables") was used to estimate a cost of common equity for the electric utility industry. These companies are shown on Schedule 8.

b. The Constant-growth DCF

Next, Staff estimated Empire'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.[38] It may be expressed algebraically as follows:

[38] 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.

$$k = D_1/P_0 + g$$

Where: k is the cost of equity;

D_1 is the expected next 12 months dividend;

P_0 is the current price of the stock; and

g is the dividend growth rate.

The term D1/P0, the expected next 12-months' dividend divided by current share price, is the dividend yield. Staff calculated the dividend yield for each of the comparable companies by dividing the 2016 fiscal year FactSet projected dividends per share (*see* Schedule 12) by the monthly high/low average stock price for the three months ending February 2016. (*See* Schedule 11).[39] Staff used the above-described stock price because it reflects current market expectations. The projected average dividend yield for the current proxy group of fifteen comparable companies is 3.78%, 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 the actual dividends per share ("DPS"), EPS and book value per share ("BVPS") for each of the comparable companies and also the projected DPS, EPS and BVPS. In reviewing actual growth rates, Staff found the historical growth rates to be quite volatile, at least for a few of the companies in the proxy group.[40] Staff also reviewed equity analysts' consensus estimates for long-term compound annual growth rates as reported by FactSet and provided by SNL Financial. The average consensus long-term growth rates for the current proxy group is currently 5.12 %. (*See* Schedule 10-6).

Based on the shorter-term projected EPS growth rate data, one may argue that electric utilities can grow at a rate of approximately 5.15 percent, but it would be unreasonable to

[39] 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.

[40] Schedule 10-1 depicts the annual compound growth rates for DPS, EPS and BVPS for each comparable company for the past ten years. Schedule 10-2 lists the annual compound growth rates for DPS, EPS and BVPS for each of the comparable companies for the past five years.

conclude that this growth rate is sustainable in perpetuity because it does not give consideration to empirical and logical information that suggests that utility companies should grow at a rate less than that of the overall economy.

Historical data also indicates that companies in the S&P 500 (a proxy for the U.S. capital markets) have retained over 60% of their earnings for reinvestment since January 1, 2009,[41] while electric utilities' retention ratio has been less than half that of the S&P 500,[42] it makes logical sense that utilities will grow at a rate less than that of nominal GDP growth. Consequently, a projected long-term, steady-state nominal GDP growth rate[43] should be considered as an upper constraint when testing the reasonableness of growth rates used to estimate the cost of equity for a regulated electric utility. Staff will provide more detail on economic growth projections when discussing the multi-stage DCF, but a high-end estimate for nominal GDP is not much higher than 4.30%, causing an estimated constant growth rate over this rate to be highly suspect.

Because Staff is not relying on the constant-growth DCF to quantify the change in the cost of equity since the 2014 rate cases, Staff's growth rate estimate for the constant growth DCF is based on some common sense restraints on sustainable growth rates and the actual growth experience of the electric utility companies that have experienced more stable growth patterns. Considering that actual long-term growth experience in the electric utility industry barely supports a constant growth rate much more than 3%, Staff will use 3.5% as the low end and 4.5% for the high end investors' expectations of a constant growth rate.

Using the growth rate range Staff established for the constant-growth DCF results in a cost of equity estimate of 7.3% to 8.3%. However, Staff will again rely on its multi-stage DCF analysis to provide what it believes to be a more reliable cost of common equity due to the non-sustainable growth rates of a few companies in its proxy group.

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[41] http://www.spindices.com/indices/equity/sp-500.

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

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

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.[44] Consequently, as in the last rate case, Staff again performed a multi-stage DCF analysis in this case and is relying primarily on this analysis to draw conclusions on the change in the cost of common equity since the 2014 rate cases because the multi-stage DCF is dynamic enough to consider changes in near-term growth rates, but still maintain a consistent perpetual growth rate as this rate should not change much, if any, because there have been no structural changes in the economy or industry to support it.

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 for the final stage much higher than the expected rate of inflation, currently 2.0% to 2.5%. The ability of a multi-stage DCF analysis to reliably estimate the cost of common equity is primarily driven by the analyst using a reasonable growth rate for the final stage because this rate is assumed to last into perpetuity. Where three stages are used, the second stage is generally a transitional phase between the high-growth first stage and the constant-growth final stage.[45]

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.[46] 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 14-1 through 14-3). Based on this set

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[44] 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.

[45] 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.

[46] In practice, Staff extended the third stage only to year 200.

of assumptions, Staff's estimated cost of equity for the current proxy group ranges from approximately 7.38% to 8.15%, mid-point of 7.76%.

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

iii. Stage two

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

iv. Stage three

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

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

The Financial Analysis Unit has access to Value Line data on *Central* region electric utility companies dating back to 1968.[47] 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.[48] 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 events related to the restructuring of the electric utility markets in the mid to late 1990s. Staff also eliminated companies that had data comparability problems due to major

[47] 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.

[48] 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.

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.

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

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

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

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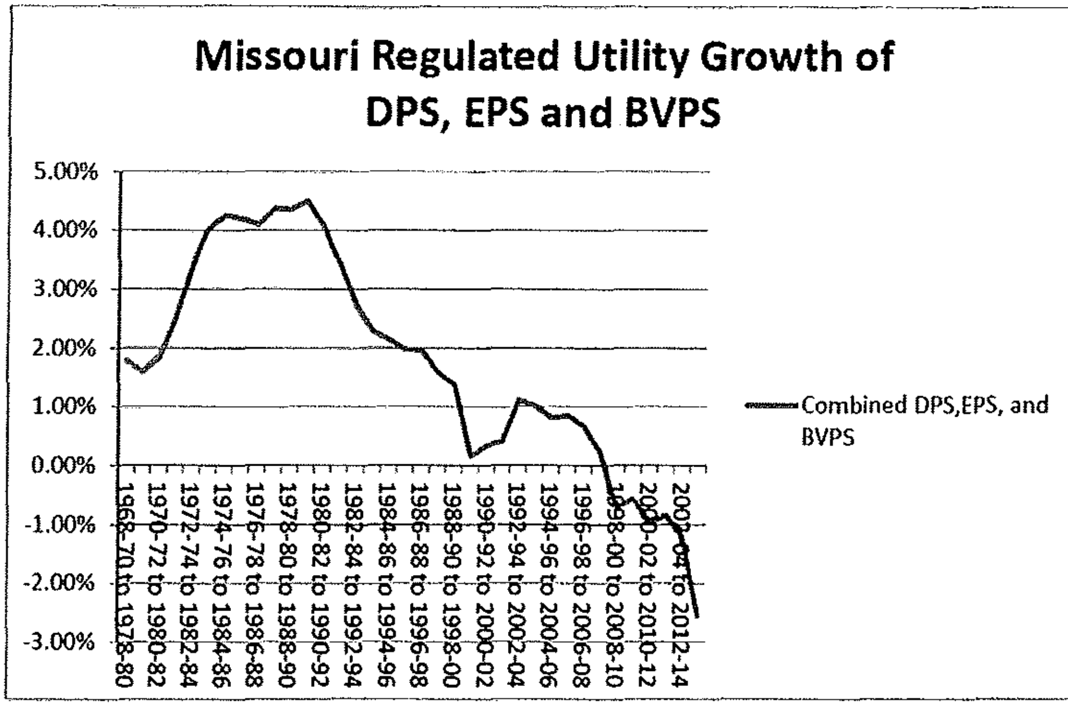

The average 10-year compound growth rates in DPS, EPS and BVPS for the period 1968 through 2015 were 1.50%, 1.30% and 2.30%, respectively, with an overall average growth rate of 1.70%. The average 10-year compound growth rates in DPS, EPS and BVPS for the period 1968 through 1999 were 3.59%, 3.00% and 2.57%, respectively, with an overall average growth rate of 3.05%. Consequently, including more recent financial data in evaluating the growth rate trends of Missouri's electric utilities actually supports the use of a lower perpetual growth rate than most ROR witnesses assume for a constant/perpetual growth rate. The above graph certainly would cause a rational investor to be skeptical of anyone that suggests their investment would consistently grow at a rate of 5% for any period of time, let alone in perpetuity.

Of Missouri's utilities, The Empire District Electric Company's business operations have been the most consistent in being limited to regulated utility operations through the period analyzed. Although Great Plains Energy has owned some non-regulated operations during the period Staff analyzed (e.g., Strategic Energy), these operations did not disrupt the financial performance of the Company to a great extent, even though they did increase Great Plains Energy's risk profile. However, Ameren has incurred significant financial problems due to its ownership of merchant generation operations in Illinois. This exposure caused Ameren to incur significant losses in recent years, which would skew any financial growth rates that include this information. Although Empire and Great Plains Energy did not incur financial difficulties due to non-regulated operations, both companies did reduce their dividends in recent years. Because of these issues that occurred around or after the recession and financial crisis in 2008 and 2009, Staff also determined the average growth of Missouri's utilities through 2007. The average 10-year compound growth rates in DPS, EPS and BVPS for the period 1968 through 2007 were 2.85%, 2.07% and 2.27%, respectively, with an overall average growth rate of 2.40%.

Obviously, the actual experienced growth rates of Missouri's electric utilities support the reasonable, if not lofty, perpetual growth rates Staff chose to use for its perpetual growth rate analysis. The actual realized growth rates of Missouri's utilities support a perpetual growth rate range of 2% to 3% rather than the 3% to 4% Staff assumed. Although these growth rates are generally characterized as "low" when discussed in the utility ratemaking arena, these growth rates are more typical of those that are used by investors when determining a reasonable price to pay for a utility stock.[49] Additionally, considering that the dividend yield from utility stocks has historically produced 2/3 of the total return on utility stocks, [50] and the fact that dividend yields for electric utilities are currently approximately 3.8%, a 1.9% capital appreciation rate in utility stocks is about what investors would expect. This translates into an approximate expected return of 5.7% for utility stocks, which is quite logical and rational in the current low-yield environment.

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

In order to evaluate the credibility of an estimated perpetual growth rate for the electric utility industry, it is important to be aware of the changing fundamentals that have occurred and continue to occur within the electric utility industry due to changes in demand for electricity. In the past, growth in electric utility earnings and dividends was primarily driven by the increase in demand for electricity and the growth of customers using electricity. However, this dynamic has changed and the demand for electricity is no longer a primary growth driver for electric utilities. The decline in electricity demand growth is illustrated in the graph below:[51]

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

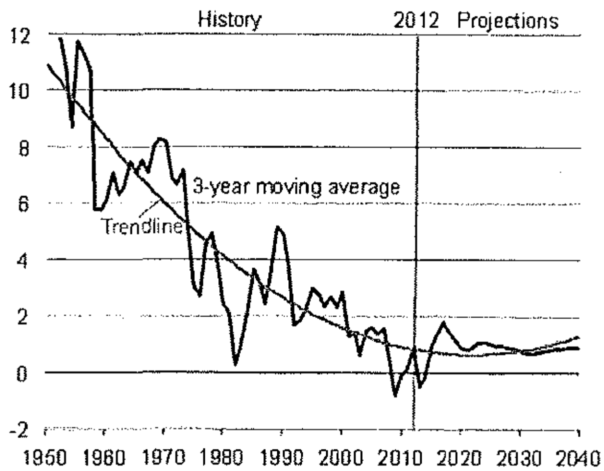
[50] Hugh Wynne, Francois D. Broquin, Saurabh Singh, "U.S. Utilities: Our Dividend Growth Model Identifies Utilities Poised to Pay More," May 20, 2011, Bernstein Research.

[51] Energy Information Administration's *2014 Annual Energy Outlook*, p. MT-16.

Electricity demand

Growth in electricity use slows, but use still increases by 29% from 2012 to 2040

Figure MT-29. U.S. electricity demand growth in the Reference case, 1950-2040 (percent)



The fact that the growth in electricity demand has been in a steady state of decline seems to explain the steady decline in electric utilities' financial performance over the period Staff analyzed in its previous discussion in this testimony. To the extent that potential financial growth for electric utilities is now limited to the ability to make additional investments and pass the cost of these investments (which includes the allowed ROR) onto a near-constant customer base, any growth higher than needed capital investment to replace existing infrastructure would seem to be highly speculative and not sustainable. However, Staff notes that much of the rate base growth for electric utilities in recent years has been due to electric utilities making investments in their coal-based generating facilities in order to comply with various emission standards. These types of investments are policy-driven, and therefore are not controllable by management (although the amount of reasonable project costs are controllable). Absent policy-driven investment requirements, it would seem that growth in investment would be limited to a rate similar to inflation because the only way to recover these costs is to raise rates on the existing customer base that is not using as much electricity.

vi. Preference for GDP Growth

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

Projected GDP growth is available from a variety of sources, such as the Congressional Budget Office ("CBO"), the Federal Reserve, the EIA, and Blue Chip Economic Forecasts. Staff will use the CBO, EIA, The Survey of Professional Forecasters published by the Philadelphia Federal Reserve, The Federal Open Market Committee ("FOMC"), and The Livingston Survey for purposes of long-term projected GDP growth. The CBO projects an annual compound growth rate in nominal GDP of approximately 4.10% through 2026[52] EIA's reference case projects an annual compound growth rate in nominal GDP of approximately 4.24% for the period 2013 through 2040,[53] The Survey of Professional Forecasters projects a 10-year annual compound growth rate in real GDP of 2.23%;[54] The Livingston Survey projects an average annual compound growth rate in real GDP of 2.25% over the next ten years;[55] and the FOMC projects a central tendency long-term real GDP growth of only 1.8% to 2.2%. 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 approximate prediction of long-term inflation and also the inflation rate which is targeted by the Federal Reserve. Based on these projections, the long-term nominal GDP growth rate is expected to be approximately in the range of 3.84% to 4.3%. These projected long-term growth rates in U.S. GDP are consistent with the current low interest rate environment, which implies a low growth, low rate of return environment. These projected GDP growth rates are even lower than what these sources projected just a few months ago when Staff prepared the Staff Cost of Service Report for the Missouri-American Water Company rate case, Case No. WR-2015-0301. Staff had determined a projected nominal GDP growth rate of 4% to 4.5% at the time it prepared its testimony at the end of last year.

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[52] https://www.cbo.gov/publication/45066.

[53] http://www.eia.gov/beta/aeo/#/?id=18-AEO2015&region=0-0&cases=ref2015&start=2015&end=2040&f=A.

[54] https://www.philadelphiafed.org/research-and-data/real-time-center/survey-of-professional-forecasters/2016/survq116.

[55] https://www.philadelphiafed.org/research-and-data/real-time-center/livingston-survey.

For purposes of quantifying the change in cost of equity from the 2014 cases, Staff will use the same GDP growth rate, 4.4%, that was used in the 2014 cases. However, as Staff notes above, recent downward revisions to expected long-term GDP have likely caused investors to lower their expected growth rates for their utility investments. Consequently, Staff's use of the 4.4% rate in its current analysis will underestimate the change in the cost of equity since 2014. When using a 4.4% GDP growth rate in Staff's multi-stage DCF results in a COE estimate of approximately 8.46% for the current proxy group. If Staff had used a 4.1% GDP growth rate, the multi-stage DCF analysis would imply a COE estimate of 8.23%.

vii. Update of Multi-Stage DCF Analysis on the Proxy Group from the most recent Missouri Electric Utility Rate Cases

Staff updated the multi-stage DCF analysis it performed on the refined proxy group from the 2014 electric utility rate cases for Ameren Missouri, Empire and KCPL. Staff's multi-stage DCF analysis for the electric utility industry assumed a perpetual growth rate range of 3% to 4% based on Staff's compilation and calculation of rolling 10-year compound growth rates for the electric utility industry for the period 1969 through 1999. Staff used the perpetual growth rate of 4.4% used in the 2014 electric utility rate cases based on the assumption that the electric utility industry could grow in perpetuity at the same rate as the expected long-term growth rate in the U.S. economy as measured by GDP. Based on stock prices for the three months through February 2016, Staff's multi-stage DCF analysis of the 2014 refined electric utility proxy group indicates a cost of equity of 7.30% to 8.08% using the 3% to 4% terminal growth rates and 8.39% using GDP for a terminal growth rate. At the time Staff had recommended the Commission reduce Ameren Missouri's allowed ROE by 25 to 75 basis points, the estimated multi-stage DCF cost of equity for this same proxy group was 7.56% to 8.32% using terminal growth rates in the range of 3% to 4%. Using GDP for a terminal growth rate, Staff had estimated the COE for the electric utility industry at 8.63%. These results imply that even when Staff used the same growth rates from the 2014 rate cases, the implied COE is slightly lower now than it was in the fall of 2014. Schedule 15 shows detailed comparisons of current implied COE estimates to implied COE estimates Staff estimated at the time it filed testimony in the Ameren Missouri, Empire and KCPL 2014 rate cases.

Staff believed it was clear at the time of the Ameren Missouri rate case that there was sufficient evidence to indicate that the COE had declined by 25 to 75 basis points since 2012.

In the subsequent Empire and KCPL rate cases, Staff's continually updated analysis indicated that the cost of equity could be as much as 100 basis points lower than it was in 2012, which would have justified an allowed ROE of below 9%. However, Staff chose to recommend all of Missouri's electric utility allowed ROEs be set based on Staff's initial estimate of a 25 to 75-basis point decline.

Considering the fact that an update of Staff's multi-stage DCF analysis from the 2014 electric utility rate cases implies that the cost of equity is still below at least the level it was when Staff performed its analysis in the Ameren Missouri rate case, the current capital and economic environment supports an allowed ROE consistent with what the Commission considered fair and reasonable just a few months ago.

H. 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. The CAPM

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 2014. Staff has yet to receive updated capital market return information through 2015, but should be able to provide this information in rebuttal testimony. For the risk-free rate (Rf), Staff used the average yield on 30-year U.S. Treasury bonds for the three-month period ending February 29, 2016; that figure was 2.82%. For beta (β), Staff relied on estimates directly calculated through an Excel spreadsheet designed specifically to be used with the SNL database of market and financial information. Although Staff is no longer using Value Line's published betas for purposes of its CAPM analysis in its direct testimony for electric and gas rate cases, because Value Line is used by many retail investors, Staff still believes Value Line's beta calculation methodology should be considered when performing a CAPM analysis. Because estimating beta is a matter of having access to financial data and performing statistical calculations, unless a financial services provider has a proprietary adjustment they make to their beta calculation, understanding the methodology used by a financial provider allows an analyst to approximately replicate betas of that provider. Fortunately, this is the case for Value Line's beta calculation methodology. Consistent with Value Line's approach to calculating beta, Staff used 5-years of historical weekly returns of the subject company and the New York Stock Exchange ("NYSE") index. The covariance of the weekly returns on the NYSE index and the weekly returns on the subject company is divided by the variance of the weekly returns on the NYSE index to determine raw beta (unadjusted beta). Staff then adjusted the raw beta using the Blume adjustment formula as used by Value Line: Adjusted Beta = (.35 + .67(Unadjusted Beta)) (*see* Schedule 16).

The average beta for the current proxy group is 0.73. For the market risk premium (Rm – Rf) estimates, Staff relied on the historical difference between earned returns on stocks and earned returns on bonds.[56] The first risk premium was based on the long-term arithmetic

[56] From Duff & Phelps *2014 Valuation Handbook: A Guide to the Cost of Capital.*

average of historical return differences from 1926-2014 – 6.00 percent. The second risk premium was based on the long-term geometric average of historical return differences from 1926 to 2014 – 4.40 percent. The results using the long-term arithmetic average risk premium and the long-term geometric risk premium are 7.22 and 6.05 percent, respectively for the current proxy group.

These cost of common equity results support the reasonableness of Staff's cost of equity estimates derived from its DCF analysis. Staff again notes that both U.S. Treasury yields and utility bond yields are quite low (at levels last experienced in the early 1960s) and that the spread between them is presently below their long-term average. It is not improbable that investors are only requiring returns on common equity in the 6 to 7 percent range for utility stocks. In fact, as Staff will explain in its other tests of reasonableness, these cost of equity estimates are consistent with common sense tests.

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[57] used for the curriculum for Chartered Financial Analyst ("CFA") Program, Staff believes this method is free of any bias from those involved in utility ratemaking. It is also a useful test because it is very straightforward and limits the risk premium to a 100-basis point range. The cost of equity is estimated by simply adding a risk premium to the yield-to-maturity ("YTM") of the subject company's long-term debt. Based on experience in the U.S. markets, the typical risk premium is in the 3% to 4% range. Considering that this is based on general U.S. capital-market experience and that regulated utilities are on the low end of the risk spectrum of the general U.S. market, a risk premium closer to 3% seems logical. This is especially true considering that regulated utility stocks behave like bonds. For the three months ended January 2016, 'A' rated long-term utility bonds and 'Baa' rated long-term utility bonds had average yields of 4.34% and 5.54% respectively.[58] Adding a 3% risk premium, the "rule of thumb" indicates a cost of common

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[57] 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.

[58] Mergent Bond Record.

equity between 7.34% and 8.54%. Adding a 4% risk premium, the "rule of thumb" indicates a cost of common equity between 8.34% and 9.54%. According to Value Line's utility bond yield data, for the twelve weeks ended February 17, 2016, 'A' rated long-term utility bonds and 'Baa' rated long-term utility bonds had average yields of approximately 4.27% and 4.80% respectively.[59] Adding a 3% risk premium, the "rule of thumb" indicates a cost of common equity between 7.27% and 7.80%. Adding a 4% risk premium, the "rule of thumb" indicates a cost of common equity between 8.27% and 8.80%.

b. Average Authorized Returns

In the past, the Commission has applied a test of reasonableness using average authorized returns published by Regulatory Research Associates ("RRA") to test the reasonableness of its allowed ROE. According to RRA, the average authorized return on equity authorized electric utilities was 9.85% in 2015 (based on 30 ROE determinations), compared to a 2014 calendar year average of 9.91% (based on 38 ROE determinations).[60] Excluding the effect of the surcharge/rider generation cases in Virginia, the average allowed electric ROEs were 9.58% for the 2015 calendar year and 9.76% for the 2014 calendar year.

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

As a further refinement, Staff also evaluated allowed ROE information for only cases that were fully-litigated as in these cases, one would expect that each issue is determined based on its own merits. Allowed returns determined in the context of a settled case are not as reliable because parties make adjustments to other elements of the ratemaking formula in order to arrive at an overall reasonable number. It has been Staff's experience that some companies do not want

[59] Value Line Selection & Opinion December 11, 2015 through February 26, 2016, except for the February 5, 2016 Selection & Opinion because it was unavailable to Staff at the time of testimony.

[60] RRA, Regulatory Focus – Major rate case decisions - -Calendar 2015 - January 14, 2016: 2015 data includes five surcharge/rider generation cases in Virginia that incorporate plant-specific ROE premiums. Virginia statutes authorize the State Corporation Commission to approve ROE premiums of up to 200 basis points for certain generation projects.

a lower ROE published in a settlement because this is a headline number. Consequently, companies may compromise on a more obscure area of the rate case in order to have a higher ROE published in the settlement. Allowed ROEs for fully-litigated cases were 9.74 % for the 2015 calendar year, and 10.03 % for the 2014 calendar year.

The allowed ROE information provides a trend that the average allowed ROEs for electric utilities have decreased since 2014.

I. 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 Empire's prudent cost of service, which includes an allowed ROR. Considering all of the information that Staff has reviewed, there does not appear to be a significant change in the capital markets to support a conclusion that the cost of equity for the electric utility industry has substantially increased or decreased since the Commission ordered an allowed ROE of 9.53% for Ameren Missouri and 9.50% for KCPL. Consequently, Staff recommends the Commission authorize an ROE for Empire in the range of 9.50 percent to 10.00 percent, with a midpoint of 9.75 percent. Staff's midpoint recommended ROE of 9.75% for Empire is approximately 25 basis points higher than the recent allowed ROEs for Ameren Missouri and KCPL because Staff added 25 basis points due to Empire's lower credit rating, which is based on the business and financial risks of Empire's regulated utility operations. Ameren and KCPL have corporate credit ratings of 'BBB+' while Empire has a corporate credit rating of 'BBB'.[61] The spreads between 'A' rated utility bonds and 'BBB'/'Baa' rated utility bonds have historically averaged approximately 45 basis points.[62] This spread would normally suggest a 15-basis point risk premium is acceptable for a company rated one notch lower (45/3 = 15). As mentioned earlier, Staff noticed from the Mergent Bond Record that spreads between 'A' rated and 'BBB'/'Baa' utility bond yield have recently significantly increased to over double the historical average. Staff's analysis using Mergent's utility bond yield constituent list (excluding the energy companies) and FINRA data for the twelve weeks

[61] S&P Ratings as of March 7, 2016. Ameren Corp. and Great Plains Energy.

[62] Mergent Bond Record.

ended March 14, 2016, showed a spread of approximately 65 basis points between 'A' rated and 'BBB'/'Baa' rated utility bonds. This spread would suggest approximately a 22-basis point risk premium is acceptable for a company rated one notch lower (65/3 = 21.67). Therefore, because of the recent increase in spreads between 'A' and 'BBB'/'Baa' rated utility bonds, Staff recommends a 25-basis point adjustment

Using an allowed ROE range of 9.50% to 10.00% for Empire results in an allowed rate of return range of 7.36 percent to 7.61 percent (*see* Schedule 18). Using the point recommended allowed ROE of 9.75% results in an allowed rate of return of 7.49%. This was calculated by applying an embedded cost of long-term debt of 5.33% and an allowed return on common equity range of 9.50% to 10.00%, with a midpoint of 9.75%, to a capital structure consisting of 48.73% common equity and 51.27% long-term debt. Because there appears to be some concern in setting an allowed return on equity based on a reasonable estimate of the cost of equity, Staff recommends the Commission set the allowed ROE at 9.75% in this case. Although this is above what Staff estimates to be the cost of equity to be in the current capital market environment, this allowed ROE is fair and reasonable considering the recent allowed ROEs the Commission authorized Ameren Missouri and KCPL.

Staff Expert/Witness: Shana Griffin

VIII. Rate Base

A. Plant in Service

1. Plant in Service updated as of September 30, 2015

Accounting Schedule 3, Plant in Service, reflects the rate base value of Empire's plant in service by account, updated through September 30, 2015, to be later trued-up through March 31, 2016.

Staff Expert/Witness: Jennifer K. Grisham

2. Plant Adjustments: Allocation to Gas

Empire records its natural gas general plant in-service balances entirely on its electric books. To ensure that Empire's electric customers only pay in rates for costs associated with electric service, Staff adjusted Empire's plant balances to remove the portion of the Company's general plant associated with Empire's natural gas business for rate case purposes.

Staff Expert/Witness: Jennifer K. Grisham

B. Depreciation Reserve

1. Depreciation Reserve as of September 30, 2015

Accounting Schedule 6, Depreciation Reserve, reflects the rate base value of Empire's depreciation reserve by account, updated through September 30, 2015, to be trued-up through March 31, 2016.

Staff Expert/Witness: Jennifer K. Grisham

2. Reserve Adjustments: Allocation to Gas

Empire records its natural gas depreciation reserve associated with general plant entirely on its electric books. So that Empire's electric customers only pay in rates for the costs to provide them electric service, Staff removed the portion of the general plant depreciation reserve associated with Empire's natural gas business for rate case purposes.

Staff Expert/Witness: Jennifer K. Grisham

3. Plant & Depreciation Reserve Adjustments: Capitalized Incentive Compensation

On an ongoing basis, Empire capitalizes to plant in service a portion of its incentive compensation for the Employee Stock Purchase Plan and the Bonus Incentive Plan ("Lightning Bolts"). Staff made regulatory adjustments to the plant in service and depreciation reserve from June 30, 2012, through September 30, 2015, the end of the update period in this case, in order to eliminate these amounts from cost of service, consistent with prior Staff policy. Since Staff removed these compensation expenses from its cost of service income statement (*see* Section X. F. 2.b.), Staff is also making an adjustment to remove these costs from rate base in this case.

Staff Expert/Witness: Jermaine Green

C. Cash Working Capital ("CWC")

The cash working capital requirements in the Company's rate base have been updated from the previous rate case, No. ER-2014-0351. Staff is using the same revenue and expense lags that were agreed to by the Company and Staff in the last case, but it has updated the adjusted test year amounts associated with each CWC Accounting Schedule line item.

Staff Expert/Witness: Jennifer K. Grisham

D. Prepayments and Materials and Supplies

The Company has utilized shareholder funds to finance prepaid items such as insurance premiums and postage. The Company is reimbursed by customers for these costs once the items are charged to expense during a subsequent period. The Staff has included these prepayments in rate base at the 13-month average level, ending September 2015. There were three prepayment accounts that were excluded in the Staff's average: Working Funds Iatan (165350), Working Funds Plum Point (165351), and KCPL Land Lease (165352). These are cash accounts, not actual investment in utility assets, and are therefore excluded from rate base.

The Company also holds a variety of materials and supplies ("M&S") in inventory so the items can be readily available when needed in performing its utility operations. Staff performed an analysis of all of Empire's M&S accounts from August 2013 through September 2015. For most accounts, there was no upward or downward trend noted. As a result, the 13-month average of Empire's M&S account balances as of September 30, 2015, the end of the Staff's update period in this case, was used to determine the average balance for these accounts. There were six M&S accounts (154100, 163025, 163081, 163086, 163316, and 163327) which showed a steady trend, either upward or downward, depending on the account, within the review period. Accordingly, Staff used the most current ending balance as a more appropriate number for these six accounts.

Empire's electric and water inventory is included on Empire's electric books and records; therefore, an adjustment entry has to be made to eliminate the water M&S from Empire's electric books. Staff used a 13-month average of Empire's water inventory to determine the level of M&S inventory that needed to be eliminated from Empire's rate base in this proceeding.

Staff Expert/Witness: Jennifer K. Grisham

E. Fuel Inventories

Coal Inventory - Staff used the results of its fuel model to calculate the annual amount of coal used by each Empire generating plant to meet its total company normalized native load. Empire operates in four retail jurisdictions: Missouri, Arkansas, Kansas, and Oklahoma. "Native load" is the kilowatt or megawatt demand placed upon Empire's electric system by its regulated retail electric customers. To determine the amount of coal inventory, the average daily burn by unit must be calculated. The average daily burn by unit is derived by dividing the annualized tons burned by the difference between 365 days and the number of annual planned outage days. Then, the average daily burn is multiplied by an appropriate number of days of inventory for each plant resulting in a burn inventory. The number of days of inventory of Powder River Basin ("PRB"), or "western" coal, for the Asbury 1 unit is set by Empire at or around 60 days. The PRB coal in 2016 will be supplied by western coal suppliers: Peabody Coal Sales, Arch Coal Sales, and Cloud Peak Energy.

Empire also normally carries an inventory of local (Illinois) bituminous coal supplied by Foresight Coal Sales, under contract; the days of inventory included for this coal is also 60 days. Staff has also used a 60-day calculation to establish Empire's rate base investment in the coal inventory maintained both at KCPL's Iatan Generating Stations (Empire is a 12% owner of Iatan 1 and 2) and Plum Point Energy Associates, LLC's Plum Point Energy Station (Empire is a 7.52% owner of Plum Point).

Staff multiplied the resulting burn inventory for each unit by the delivered cost of coal per ton for that unit as calculated by Staff. To this total, Staff then added the fixed cost of basemat coal established in the prior Empire Rate Case No. ER-2011-0004 for each unit, except for Plum Point. The basemat for the Plum Point unit is capitalized as part of plant in service costs. Basemat coal is the bottom portion of a coal pile that is not usable as fuel due to contamination by soil, clay, and other contaminants. The total cost of the burn inventory and basemat was multiplied by Staff's energy jurisdictional factor to arrive at the Missouri allocated amount with the result being the amount that is reflected as part of Fuel Inventories in Accounting Schedule 2, Rate Base.

Fuel Oil Inventory - Staff used the 13-month average inventory quantities and a weighted average price for oil inventory levels as reported in the Company's Coal and Oil Inventory Reports provided in response to Staff's Data Request No. 0022.

Gas Stored Underground – According to Empire, the Company is not renewing its natural gas storage agreement with Southern Star Central Gas Pipeline, Inc. ("SSCGP") when it expires on March 31, 2016. After that time, Empire will no longer be storing any natural gas underground. Therefore, Staff did not include any inventory cost for Gas Stored Underground in rate base.

Staff Expert/Witness: Keith D. Foster

F. Amortization of Electric Plant

Staff has adjusted the amortization reserve for electric plant intangible assets to reflect the updated balances through September 30, 2015, the end of the update period for this case. The amortization reserve balance as of September 30, 2015, is $12,739,926 and was included as an offset to rate base in Staff's Accounting Schedules.

Staff Expert/Witness: Jennifer K. Grisham

G. Amortization of PeopleSoft Intangible Asset

Staff has adjusted the intangible asset for the PeopleSoft software costs to reflect the updated balances through September 30, 2015. The regulatory asset balance, as of the end of the update period September 30, 2015, is $197,209 and was included as an addition to rate base in Staff's Accounting Schedules.

Staff Expert/Witness: Jennifer K. Grisham

H. Customer Deposits

The amount of customer deposits shown on Accounting Schedule 2, Rate Base, represents a 13-month average (September 2014 - September 2015) of Empire's customer deposits. Customer deposits are funds received from customers as security against potential loss arising from failure to pay for utility service. Staff included a representative ongoing level of $10,892,877 as an offset to rate base.

Interest on customer deposits is also included in the Company's rates because customers should receive a reasonable rate of return on their deposits until the monies are refunded to them. The appropriate amount of interest to include in the Company's expenses can be determined by review of the applicable sections of Empire's current filed tariff. The tariff (Section 3, Page 5) states that the "interest rate paid upon return of a deposit, per annum, compounded annually shall be equal to the prime rate published in the Wall Street Journal as being in effect on the last business day of December of the prior year plus 1%." The prime rate in effect as of December 31, 2014, was 3.25%. One percent was added to this rate for a total of 4.25% interest rate on customer deposits. The amount of interest on customer deposits, $462,947, is included in Staff Accounting Schedule 10, Adjustments to the Income Statement.

Staff Expert/Witness: Jennifer K. Grisham

I. Customer Advances

Customer advances are funds provided to Empire by individual customers of the Company to assist in recovering the costs of electric plant construction projects specific to the customers under certain circumstances. Unlike customer deposits, no interest is paid to customers for the use of this money. Therefore, it is appropriate to include these funds as an offset to rate base. There has been a significant decrease in the balance of this account since the last rate case. The ending balance as of September 30, 2015, the end of the Staff's update period in this case, is shown on Accounting Schedule 2, Rate Base.

Staff Expert/Witness: Jennifer K. Grisham

J. Accumulated Deferred Income Taxes ("ADIT")

Empire's ADIT represents, in effect, a net prepayment of income taxes by customers prior to tax payment by Empire. For example, because Empire is allowed to deduct depreciation expense on an accelerated basis for income tax purposes, the amount of depreciation expense used as a deduction for income taxes purposes by Empire is considerably higher than the amount of 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 tax reserves to the future. The net credit balance in the ADIT accounts reserve represents a source of cost-free funds to Empire. Therefore, Empire's rate base is reduced by the ADIT balance to avoid having customers pay a return on funds that are provided cost-free to the Company. Generally, deferred income taxes associated with all book-tax timing differences created through the ratemaking process should be reflected in rate base. Staff has decided to take this approach in calculating the ADIT rate base offset amount in this case.

The deferred tax impact associated with the following past tax timing differences were included in Staff's rate base offset: Accelerated Depreciation, Loss on Hedge Transactions, Gain on Hedge Transactions, License Software Amortization, Loss on Reacquired Debt, Ice Storm Expenses, Deferred Federal Tax Asset-Miscellaneous, Deferred Tax Liability-Iatan Deferred Charges, Deferred Tax-ITC Tax Basis-Iatan, Contributions in Aid of Construction, Post-retirement Benefits – Pensions and Capitalized Interest.

In December 2015, the U.S. Congress passed a "tax extender" package which includes an extension of the availability of bonus depreciation benefits through the end of 2014. Bonus depreciation allows the utility to deduct capital investments more quickly than under normal accelerated tax depreciation allowances. The bonus depreciation benefit was scheduled to expire at the end of 2014 but was again extended in December 2015. Staff's direct case reflects the tax impacts of bonus depreciation on Empire's accumulated deferred income tax rate base off-set amount.

Staff Expert/Witness: Amanda C. McMellen

K. Vegetation Management Tracker Regulatory Asset

The tracker amount for this case is $2,870,695, calculated as the difference between the vegetation management costs and Empire's rate recoveries of vegetation management costs from September 30, 2014, to July 31, 2015. Staff included these amounts in its rate base. Staff's recommendation does not include any carrying costs for the current Empire vegetation management tracker balance.

Staff Expert/Witness: Jermaine Green

L. Iatan and Plum Point Carrying Costs

1. Iatan 1

Pursuant to Empire's regulatory plan approved by the Commission in Case No. EO-2005-0263, Empire deferred certain "carrying costs" associated with the Iatan 1 AQCS investment past its in-service date into Account 182308, Iatan Deferred Carrying Costs. (The deferral of carrying costs after a project's in-service date is also known as "construction accounting"). In the *Report and Order* in KCPL's Case No. ER-2010-0355, the Commission disallowed certain costs that had been booked to the Iatan accounts. The effect of these disallowances reduces the balance of the Iatan 1 AQCS plant balance. In Empire's Case No. ER-2012-0345, Staff removed any construction accounting allowances associated with the portion of Iatan 1 AQCS approved disallowances that were allocated to Empire from its rate base and expense amortization calculations. In Empire's most recent rate case, Case No. ER-2014-0351, Staff used the balance in Account 182308 as of June 30, 2012, and the annual amortization expense included in Staff's Accounting Schedules in Case No. ER-2012-0345, to determine the unamortized balance as of August 31, 2014, for this item to include in rate base. For the current rate case, Staff calculated the remaining unamortized balance as of September 30, 2015, to include in rate base.

Staff Expert/Witness: Keith D. Foster

2. Iatan 2

Pursuant to Empire's regulatory plan approved by the Commission in Case No. EO-2005-0263, Empire deferred certain "carrying costs" associated with the Iatan 2 generating unit investment past its in-service date into Account 182332, MO IatanII Df Chg ER-2010-0130. In the *Report and Order* in KCPL's Case No. ER-2010-0355, the Commission disallowed certain costs that had been booked to the Iatan accounts. Staff has removed any construction accounting allowances associated with the portion of Iatan 2 disallowances that were allocated to Empire from its rate base and expense amortization calculations. The balance of Iatan 2 carrying costs was also reduced by Empire's deferral of fuel and purchased power expense savings it has incurred due to the addition of Iatan 2 to its generating system from the unit's in-service date through June 30, 2012. In Empire's most recent Case No. ER-2014-0351, Staff used the balance in Account 182332 as of June 30, 2012, and the annual amortization expense included in Staff's

Accounting Schedules in Case No. ER-2012-0345 to determine the unamortized balance as of August 31, 2014, for this item to include in rate base. For the current rate case, Staff calculated the remaining unamortized balance as of September 30, 2015, to include in rate base.

Staff Expert/Witness: Keith D. Foster

3. Plum Point

Pursuant to Commission approval of the *Non-Unanimous Stipulation and Agreement and Joint Proposal Regarding Certain Procedural Matters* dated February 25, 2010, in Case No. ER-2010-0130, Empire deferred certain "carrying costs" associated with the Plum Point generating unit investment past its in-service date into Account 182331, MO PlumPt Df Chgs ER-2010-0130. Based on the results of its Construction Audit and Prudence Review for Plum Point (submitted in Case No. ER-2011-0004), Staff recommended one disallowance to Empire's Plum Point plant balances. In Empire's most recent Case No. ER-2014-0351, Staff used the balance in Account 182331 as of June 30, 2012, and the annual amortization expense included in Staff's Accounting Schedules in Case No. ER-2012-0345 to determine the unamortized balance as of August 31, 2014, for this item to include in rate base. For the current rate case, Staff calculated the remaining unamortized balance as of September 30, 2015, to include in rate base.

Staff Expert/Witness: Keith D. Foster

4. Iatan Carrying Costs Amortization

Pursuant to earlier agreements, Empire deferred certain carrying costs (monthly debt and equity-derived carrying charges) and monthly deprecation for its Iatan 1 AQCS Account 182308 - Iatan Deferred Carrying Costs, Iatan 2 Account 182332 - MO IatanII Df Chg ER-2010-0130, and Plum Point Account 182331 - MO PlumPt Df Chgs ER-2010-0130. This deferral of carrying costs on the Iatan 1 AQCS, Iatan 2, and Plum Point investments was authorized under previous agreements, approved by the Commission. In Empire's Case No. ER-2012-0345, Staff recommended amortization of these carrying costs into cost of service using a composite amortization rate derived from dividing the total depreciation expense for each plant by the total plant balance for each plant. Staff used these composite rates and calculated amortization amounts of $84,729 for Iatan 1 AQCS, $44,828 for Iatan 2, and $1,987 for Plum Point. Staff used the same amortization amounts in this case.

Staff Expert/Witness: Keith D. Foster

5. Southwestern Power Administration ("SWPA") Hydro Reimbursement

On September 16, 2010, Empire received a payment in the amount of $26,563,700 from the Southwestern Power Administration ("SWPA"), to compensate Empire for the expected financial impact of a future reduction in capacity at its Ozark Beach hydroelectric plant. The reduction in capacity at Ozark Beach is due to the Energy and Water Development Act of 2006, federal legislation which requires a decrease in available head waters at Ozark Beach. In Case No. ER-2011-0004, Empire agreed to flow the SWPA payment back to the customers over a ten-year period via a tracker mechanism. Staff has included as an offset to rate base the unamortized balance of this regulatory liability.

Staff Expert/Witness: Amanda C. McMellen

IX. Allocations

A. Corporate Allocations

As discussed earlier in this Report, Empire is engaged in both regulated and non-regulated business operations. Staff reviewed Empire's methods for assigning and allocating costs to its regulated electric, gas, and water operations, as well as to its various non-regulated operations. Under Empire's corporate cost allocation system, costs are either directly assigned by Empire to business units (Empire refers to this assignment as "direct billing"), indirectly allocated to the business units, or allocated through use of a general allocation factor.

Under the direct assignment approach, Empire directly assigns certain costs to its regulated electric operations either by use of vendor invoices or by labor charges. In the case of assignment by vendor invoice, each vendor invoice that includes charges for goods and services that directly benefit a specific business unit has the invoiced costs directly assigned to the appropriate corresponding business unit. In the case of assignment by labor, all employees are required to record their time electronically based on the amount of time each employee spends each month working for each business unit. The system then allocates a portion of that employee's salary, including associated payroll taxes and fringe benefits, to the appropriate business unit. However, Staff has concerns with the reliability of Empire's time reporting; for example, Staff did not find any indication that any employee time was recorded or allocated to Empire's recent strategic alternatives or acquisition activities. In addition, Staff noticed that certain employees did not record any time to non-regulated operations. Staff has proposed an adjustment to account for these non-recorded allocations, which is described in Section X. I. 24.

Empire's indirect allocation factor is based upon a "unit of service method," which is employed by the Company in the event that incurred costs cannot be directly billed to the individual business units as described above. Empire uses the unit service method based on certain unit drivers. Examples of Empire's unit drivers are as follows: number of vouchers, number of active customers, number of purchase orders, and number of personal computers. An allocation rate is then calculated based on information obtained from various general ledger entries and adjusted periodically.

For costs that cannot be directly assigned, or that have no unit drivers, the Company uses a General Corporate Allocator it refers to as a "Modified Massachusetts Formula." A "Massachusetts Formula" is a general allocation factor based upon three (3) separate measurements of directly assigned costs, and which is used to allocate a company's common costs that cannot be reasonably directly assigned or indirectly allocated to a company's business units. The "Modified Massachusetts Formula" used by Empire consists of the averages of (1) profit margin, (2) payroll, and (3) net property, plant, and equipment. Staff modified some of the various allocation factors to reflect Staff's adjusted numbers that were included in its cost of service. Please reference Staff's Exhibit Modeling System ("EMS") that was filed with its cost of service report in this case for the allocation factors used by Staff.

Staff has further concerns regarding Empire's allocation methodologies. For one, it appears that Empire may not properly assign a portion of its common costs to its water and non-regulated operations. Such a methodology would overstate the costs to provide electric service while understating the cost to provide water service and non-regulated operations. Staff has proposed an adjustment to account for these common costs, which is described in Section X. I. 24. Other issues of concern that bear further investigation at a future date include: (1) whether or not common costs are excluded from base amounts when determining common cost allocation percentages; (2) whether or not there are any outside services charges that should be allocated across Empire's businesses as a common cost; and (3) whether or not Empire's application of the "Modified Massachusetts Formula" over-allocates costs to its electric business. This is not an all-inclusive list. Staff reserves the right to identify any additional issues as we do further investigation.

Staff Expert/Witness: Keith D. Foster

B. Jurisdictional Allocation Factors

Jurisdictional allocation factors are used to allocate demand-related and energy-related costs to the applicable jurisdictions. Fixed costs, such as the capital costs associated with generation and transmission plant, are allocated on the basis of demand. Variable costs, such as fuel, are more appropriately allocated on the basis of energy consumption. In this case, demand-related and energy-related costs are divided among three jurisdictions: Missouri Retail Operations, Non-Missouri Retail Operations and Wholesale Operations. The particular allocation factor applied is dependent upon the type of cost that is being allocated.

1. Demand Allocation Factor

Demand refers to the rate at which electric energy is delivered to a system to match the requirements of its customers ("load"), generally expressed in kilowatts ("kWs") or megawatts ("MWs"), either at an instant in time or averaged over a specified time interval. System peak demand is the largest electric requirement ("load") that occurs within a specified period of time, (e.g. hour, day, month, season and year) on a utility's system. Since generation units and transmission lines are planned, designed, and constructed to meet a utility's anticipated system peak demands, plus required reserves, the contribution of each of Empire's three jurisdictions: Missouri Retail Operations, Non-Missouri Retail Operations and Wholesale Operations, coincident to the system peak demand, *i.e.*, each jurisdiction's demand at the time of the system peak, is the appropriate basis on which to allocate these facilities. Thus, the term coincident peak ("CP") refers to the load, generally in kWs or MWs, in each of the jurisdictions that coincides with Empire's overall system peak recorded for the time period in the corresponding analysis. Staff is utilizing a Twelve Coincident Peak ("12 CP") methodology to determine demand allocation factors for Empire. Staff determined the demand allocation factor for each jurisdiction using the following process:

a. Identify Empire's peak hourly load in each month for the time period October 2014 through September 2015 and sum the hourly peak loads.

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

c. Divide b. by a. above.

The result is the allocation factor for each jurisdiction:

Retail Operations:	
Missouri -	.8372
Non – Missouri -	.1077
Wholesale Operations:	.0551

2. Energy Allocation Factor

Variable expenses, such as fuel, are allocated to the jurisdictions based on energy consumption. The energy allocation factor, for each individual jurisdiction, is the ratio of the normalized annual kilowatt-hour ("kWh") usage of each particular jurisdiction to the total normalized Empire kWh usage. The kWh usage data includes adjustments for anticipated growth, annualizations, and non-normal weather. Staff witnesses Ashley R. Sarver and Robin Kliethermes, respectively, provided the growth and annualization adjustments. Staff witness Seoung Joun Won provided the weather and days adjustments. Staff has calculated the following energy allocation factors for the particular jurisdictions, utilizing the twelve month period ending August 2014:

Retail Operations:	
Missouri -	.8238
Non – Missouri -	.1105
Wholesale Operations -	.0657

Staff witness Keith D. Foster used these demand and energy jurisdictional allocation factors in determining Staff's cost of service for Empire in this case.

Staff Expert/Witness: Alan J. Bax

X. Income Statement

A. Rate Revenues

1. Introduction

Since the largest component of operating revenues results from rates charged to Empire's Missouri retail customers, a comparison of operating revenues with cost of service is fundamentally a test of the adequacy of the currently effective Missouri jurisdictional retail electricity rates. If the overall cost of providing service to Missouri retail customers exceeds operating revenues, an increase in the current rates that Empire charges to Missouri retail customers for electricity is appropriate.

One of the major tasks in a rate case is not only to determine whether a deficiency (or excess) between cost of service and operating revenues exists, but also to determine the magnitude of any such deficiency (or excess). Any deficiency (or excess) identified can only be made up (or otherwise addressed) by adjusting Missouri retail rates (i.e., rate revenues) prospectively, on a going-forward basis.

Staff Expert/Witness: Ashley R. Sarver

2. Definitions

Operating Revenues are composed of Retail Rate Revenue and Other Operating Revenue. Each is defined respectively as follows:

Retail Rate Revenue: Test year rate revenues consist solely of the revenues derived from the current rates Empire charges for providing electric service to its Missouri retail customers (i.e., native load and customer charges). Empire's charges are determined by multiplying each customer's usage by the per unit rates established in its tariff. Empire's tariff provides that different rates apply to different types of charges (demand vs. energy) and different times of the year (summer vs. winter); and to customers in different rate classes (differentiation by type and amount of use). Revenues from the Fuel Adjustment Clause ("FAC") represent collections or refunds of prior period fuel costs and are excluded in determining the annualized level of ongoing rate revenues.

Other Operating Revenue: This category includes revenues from such items as forfeited discounts, reconnect charges, rent from electric property, and other miscellaneous charges.

Staff Expert/Witness: Ashley R. Sarver

3. The Development of Rate Revenue in this Case

The objective of this section is to determine normalized and annualized test year usage and revenues by rate class. The intent of Staff's adjustments to test year Missouri usage and rate revenues is to determine the level of revenue that the Company would have collected on an annual, normal-weather basis, based on information "known and measurable" at the end of the update period.

The two major categories of revenue adjustments are known as "normalization" and "annualization." Normalization adjustments eliminate the impact from revenues of test year events that are unusual and unlikely to be repeated in the years when the new rates from this case are in effect. To eliminate the impact of test year weather on revenues is an example of a normalization adjustment. Annualizations are adjustments that re-state test year results as if conditions known at the end of the update period had existed throughout the entire test year. Adjustment for customer growth is an example of an annualization.

Staff Expert/Witness: Ashley R. Sarver

4. Regulatory Adjustments to Update Period Usage and Rate Revenue

a. Update Period Adjustment

For purposes of this case, Empire used Staff's EMS run filed March 26, 2015, in Empire's last rate case, Case No. ER-2014-0351, as a starting point for any usage and revenue adjustments. Empire then updated usage and corresponding revenues for changes in customer growth and the rate increase that took effect on July 26, 2015. Although Staff will also use the retail revenues from Staff's EMS run filed March 26, 2015, as a starting point, Staff will update the retail revenues and usage for changes in normalized and annualized sales through the end of September 30, 2015, to provide a more current basis for the revenue calculation.

Staff Expert/Witness: Robin Kliethermes

b. Weather Variables

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

Source of Weather Data – In the quantification of the relationship between test year weather and energy sales, Staff used weather observations of the Springfield Regional Airport ("SGF") in Springfield, Missouri, for the update period, October 1, 2014, through September 30, 2015.

As a measure of "normal" weather, Staff used a 30-year period of "climate normals" ("normals") by the National Climatic Data Center ("NCDC") of the U.S. National Oceanic and Atmospheric Administration ("NOAA"). According to NOAA, a climate normal is defined as the arithmetic mean of a climatological element computed over three consecutive decades.[63] To conform to the NOAA's three consecutive decades for determining normal temperatures, Staff used observed maximum and minimum daily temperatures for the 30-year period of January 1, 1981, through December 31, 2010. Therefore, Staff bases its calculations on the time period of the most recent climate normals produced by NCDC.[64]

Although the definition of normal weather is relatively simple, the actual calculations may be more complicated. Inconsistencies and biases in the 30-year time series of daily temperature observations occur if weather instruments are relocated, replaced, or recalibrated. Changes in observation procedures or in an instrument's environment may also occur during the 30-year period. NOAA accounted for these anomalies in calculating the normal temperatures it published in July 2011.

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

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

Staff verified the adjustments for anomalies in the SGF time series by direct communication with NCDC, and through Staff's own review of the daily observations. According to NCDC, the serially-complete monthly minimum and maximum temperature data sets have been adjusted to remove all inconsistencies and biases due to changes in the associated historical database. In addition, NCDC confirmed that the observed temperature data needs no adjustment in the period after 2001. Furthermore, Staff's review of NCDC's peer-reviewed, published paper[65] that explains the accuracy of the NCDC's monthly temperature series homogenization procedure for removing documented and undocumented anomalies, and found it to be meteorologically and statistically sound.

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

Definition of Weather Variables - Because weather fluctuates greatly from day-to-day, the SGF temperature variables required to weather-normalize sales are two-day weighted daily mean temperatures of the update period actual and the 30-year normal. The day's daily mean temperature is generally defined as the simple average of the day's maximum daily temperature and minimum daily temperature. The daily two-day weighted mean temperature is calculated using the previous day's mean daily temperature with a one-third weight and the current day's mean daily temperature with a two-thirds weight.[66]

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

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

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

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

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

This results in the normal extreme being the average of the most extreme temperatures in each year of the 30-year normals period. The second most extreme temperature is based on the average of the second most extreme day of each year, and so forth. Staff's calculation of daily normal temperatures is not the same as NOAA's calculation of smoothed daily normal temperatures. Because the test year temperatures do not follow smooth patterns from day to day, Staff calculated normal daily temperatures based on the rankings of the actual temperatures of the update period.

Staff Expert/Witness: Seoung Joun Won Ph.D.

c. Weather Normalization

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

Staff used the most recent temperature and load data available for the updated period of October 1, 2014, through September 30, 2015, to capture a more likely, forward-looking indicator of non-weather electricity usage per customer. February 2015 experienced temperatures colder than normal, and June 2015 through July 2015 experienced temperatures hotter than normal, resulting in electric energy usage above that which would have been expected under normal weather conditions. January 2015 and August 2015 experienced temperatures more mild than normal resulting in usage below that which would have been anticipated under normal conditions. The temperatures used by Staff in the update period deviated from normal, thus Staff performed a weather impact analysis.

Staff's model and methodology contained elements important in the class level weather normalization process; in particular, use of daily load research data to determine non-linear, class 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 Robin Kliethermes to be used in the normalization of revenues for the weather sensitive classes: Residential ("RG"), Commercial ("CB"), Small Heating ("SH"), Total Electric Building ("TEB") and General Power ("GP") classes.

Staff did not weather normalize the Large Power Service ("LP") class. The members of this class are not homogeneous and, consequently, a weather response function created for one ıember should not be applied to any other member. In addition, individual LP customer hourly usage data is not available. Staff concludes it is both appropriate and necessary to annualize rather than normalize LP for changes in customer usage and count. S*ee* Section X. A. 4. f. regarding Large Power Annualization by Staff witness Robin Kliethermes for a more detailed explanation of the annualization adjustments for the LP class.

Staff Expert/Witness: Seoung Joun Won, Ph.D.

d. 365-Days Adjustment

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

For weather sensitive classes, revenue months are an aggregation of bill cycles and begin on the first day of the first billing cycle and end on the last day of the last billing cycle. This aggregation of bill cycles may or may not coincide with a 365-day calendar year. In order to account for this difference, a "365-days adjustment" was calculated to convert the annual weather normalized revenue month usage to associate with the annual weather normalized calendar month usage. The adjustment was made to the update period months in proportion to the actual usage occurring in each month and then appropriate rates were applied to determine the revenue adjustment.

For the Missouri Large Power class, rate revenue and usage is measured by revenue month (the period of time over which the staggered bill cycles result in each customer being billed precisely once) rather than by calendar month. The difference between total usage during the update period and 365 days gives us the 365-days adjustment.

Staff Expert/Witnesses: Robin Kliethermes and Seoung Joun Won, Ph.D.

e. Normalization and Annualization of Billing Determinants

Staff normalized and annualized billing determinants for the RG, CB, SH, TEB, and GP rate classes, based on the normalized and annualized kWh factor.[67] For example, if the normalized and annualized kWh factor is 0.97 for the month of September in the RG rate class, then the total actual usage for that month and that rate class is decreased by 3%.

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

The GP and TEB class billing units were similarly adjusted; however, the rate classes were subdivided by voltage with separate normalization and annualization adjustments being applied to each voltage level.

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

Staff Expert/Witness: Robin Kliethermes

[67] The normalized and annualized factors represent the impact of the weather normalization adjustment and the 365 day adjustment on actual usage calculated by Staff witness Seoung Joun Won.

f. Missouri and Non-Missouri Large Power ("LP") and Feed Mill & Grain Elevator Service ("PFM") Annualizations

Staff determined annualized, normalized update period usage and revenues for the rate classes LP and PFM on an individual customer basis.

The adjustments are for the update period of October 1, 2014, through September 30, 2015. There were 38 customers in the Missouri LP rate class at the beginning of the update period: 3 customers switched to the GP class during the update period leaving 35 customers in the LP class at the end of September 2015.

Because each LP customer uses significant amounts of electricity, and the class is heterogeneous in electric use and load factor, class sales and revenues were annualized on an individual customer (account) basis. Each Missouri LP customer's individual monthly demand and energy use, measured over multiple years prior to the update period in addition to the 12 months of the update period, was examined graphically to determine whether an adjustment was needed.

Out of the 38 Missouri LP customers, no customer's loads were adjusted. Since three LP customers switched during the update period, Staff removed those customer's loads and revenues from the LP class and added those customers to the GP class. Staff also annualized the thirteen non-Missouri LP customers on an individual customer (account) basis.

Out of the 10 PFM customers, no PFM customer's load was adjusted. One customer entered the PFM rate class; therefore that customer was annualized to reflect the gain.

Staff Expert/Witnesses: Robin Kliethermes, Kim Cox, Michelle A. Bocklage

g. Adjustments for Non-Missouri classes

Staff adjusted the RG, CB, SH, TEB, and GP classes' usage for non-Missouri customers for weather both to provide normalized kWh and for the days adjustment. These adjusted usages were provided to the Staff auditors for growth. Once Staff applied the growth adjustment, the final normalized and annualized usage was provided to Staff witness Shawn E. Lange for inclusion in Net System Input ("NSI"), and to Staff witness Alan J. Bax for inclusion in jurisdictional allocations.

Staff Expert/Witness: Robin Kliethermes

h. Rate Switching

During the update period, excluding residential customers, approximately 37 customers switched rate classes. Table 1, below, shows a summary of the number of customers that switched between classes.

Table 1: Update Period Rate Switchers

	2014			2015								
Rate	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**
Residential	0	0	0	0	0	0	0	0	0	0	0	0
Commercial	-34	-31	-30	-30	-31	-30	-27	-24	-24	-5	-2	0
Small Heating	19	17	17	17	17	17	18	18	18	0	-1	0
General Power	11	10	9	10	10	9	6	2	2	2	2	0
Tot.Elec. Bldg	7	7	7	6	6	6	5	4	4	3	1	0
Large Power	-3	-3	-3	-3	-2	-2	-2	0	0	0	0	0
Total Retail	0	0	0	0	0	0	0	0	0	0	0	0

Billing data indicated that customers represented in Table 1 switched rate classes for economic reasons rather than for changes in load. Customers who switched between classes due to changes in load were annualized through the customer growth adjustment. The overall effect of rate switching on usage nets to zero (one class' increase exactly equals the other class' decrease), however the overall effect of rate switching is a slight decrease to revenue.

Those customers who switched into and out of each of these classes were handled separately. The billing units and revenues of these customers were removed from their original rate code and their usage was added to their final rate code where it was re-priced to match rates in the final rate code.

Staff Expert/Witness: Robin Kliethermes

i. Customer Growth (Annualization)

Staff made customer growth adjustments to test year kWh sales and rate revenue to reflect the additional kWh sales and rate revenue that would have occurred if the number of customers taking service at the end of the update period (September 30, 2015) had existed throughout the entire test year. Staff calculated customer growth for the RG, CB, SH, TEB, and GP customer classes.

The only retail customer rate classes for which this approach is not taken is the Large Power ("LP") group and the Feed Mill and Grain Elevator Service ("PFM") group. The process used for the LP and PFM rate classes is described in the above subsection f. of the Report. Staff's customer growth adjustment to test year usage and resulting revenues for all retail customer groups combines the results of the analysis described above for RG, CB, SH, TEB, and GP in order to provide the annualized level of sales and revenues through the end of September 2015.

Staff Expert/Witnesses: Ashley R. Sarver and Robin Kliethermes

j. Annualization of Excess Facility Charge Revenues

These revenues result from charges to customers for additional distribution facilities provided in excess of the distribution facilities normally made available to similarly sized customers. Staff annualizes these revenues for changes in the distribution facilities provided during the update period to determine the revenue that the Company would have earned had these additional facilities been in use the entire update period.

Staff Expert/Witness: Robin Kliethermes

k. Praxair and Special Contract Revenue Imputation

Staff reviewed Praxair on an individual customer basis. After reviewing the update period data for Praxair, Staff determined that no annualization adjustment was required for that customer. The special treatment of the interruptible credits associated with Special Transmission Service Contract: Praxair, Schedule SC-P, continues effective through the update period; however, revenues were imputed as if the contract did not exist to prevent harm to other ratepayers.

Staff Expert/Witness: Sarah L. Kliethermes

5. Other Revenues

a. FAC Revenues

Staff removed from the Fuel Adjustment Clause ("FAC") revenues from the Company's starting point. This adjustment is made because this revenue will now be collected in base rates rather than through the FAC.

Staff Expert/Witness: Ashley R. Sarver

b. Unbilled Revenues

Staff has eliminated unbilled revenue from its determination of revenue requirement to ensure only 365 days of revenue are included and to reflect revenues on an "as billed" basis. The recording of unbilled revenue on the books of the Company recognizes sales of electricity that have occurred, but have not yet been billed to the customer. Therefore, it is necessary for Staff to remove unbilled revenue in order to reach an accurate revenue requirement based upon electricity sales billed to and revenues collected from Missouri customers.

Staff Expert/Witness: Ashley R. Sarver

c. Gross Receipts Revenues

For this item, Empire acts merely as a collecting agent and remits the taxes collected from customers to the appropriate taxing entities. The Gross Revenue Taxes ("GRT"), also known as city franchise taxes, included on a customer's bill are collected by the Company and remitted to the appropriate taxing authority. The GRT included on a customers' bill is recorded as revenue on the books of the Company, with a corresponding charge booked to GRT expense. Theoretically, the revenue and expense offset one another and, therefore, have no effect on net income. GRT are reported as both a revenue and expense item on Empire's books. Staff has made adjustments to eliminate both the revenue and expense associated with GRT.

Staff Expert/Witness: Ashley R. Sarver

d. SO2 Allowances

On January 18, 2005, the Commission approved the *Unanimous Stipulation and Agreement* relating to Empire's "SO2 Allowance Management Policy ("SAMP")" in Case

No. EO-2005-0020 ("2005 Agreement"). In this document, the parties agreed that Empire should be allowed to manage its sulfur dioxide ("SO2") emissions allowance inventory according to the SAMP as detailed in the 2005 Agreement. In this case, Case No. ER-2016-0023, Staff is not proposing an adjustment to SO2 Allowances.

SO2 Allowances are currently reflected in Empire's FAC calculations and Staff recommends that this treatment continue.

Staff Expert/Witness: Ashley R. Sarver

e. Renewable Energy Credits ("REC")

In 2005, Empire began receiving wind energy from Elk River Wind farm pursuant to a contract. In addition, Empire began receiving wind energy from Cloud County Wind Farm in 2008, also pursuant to contract. Empire is currently receiving wind energy from both of these entities to meet its customers' energy demand. As a result of these contracts, Empire receives Renewable Energy Credits or Certificates ("RECs"), which are credits issued under the Center for Resource Solutions' "green-e" program to certify that one megawatt-hour of electricity has been generated by a facility engaged in the production of renewable energy, such as wind, solar or biomass. RECs are tradable and can be bought and sold. Staff made an adjustment to remove non-Missouri jurisdictional accounts and to decrease REC revenues to the level realized during the twelve months ending September 30, 2015, the end of Staff's updated period.

Staff Expert/Witness: Ashley R. Sarver

f. Water Revenues

Empire recorded electric revenue amounts that relate to reconnect charges, trip charges, late fees, and return check fees associated with Empire's water business. Staff has also eliminated these water revenue amounts related to the update period (12 months ending September 30, 2015) from the revenue requirement in this case.

Staff Expert/Witness: Ashley R. Sarver

g. Coal Fly Ash Revenues

"Coal fly ash" is a byproduct created as a result of the burning of coal in generating stations to produce electricity. Fly ash has a number of possible industrial uses, primarily as an ingredient in concrete products. Over the past several years, Empire has been selling its fly ash to several different industrial companies to be used in concrete. By recycling fly ash, Empire not only receives a profit, but also provides positive environmental benefits. During the test year (EMS ER-2014-0351), Empire collected $64,826 of revenue for the sale of this product. Staff analyzed a five-year average based on the updated test year period 12-months ending September 30, 2015. There were no material differences since the last case so no adjustments to test year fly ash revenue amounts were made.

Staff Expert/Witness: Ashley R. Sarver

h. Miscellaneous Revenues

Empire's miscellaneous other revenues consist of provisions for rate refunds, forfeited discounts, rents from property, reconnect, and surge arrester fees.

Staff's analysis reflected a review of these revenue levels over a five-year period ending September 30, 2015. Based upon Staff's review, the miscellaneous revenue levels at a twelve-month period ending September 30, 2015, appear reasonable for inclusion in customer cost of service, except for the provision of rate refunds. Staff made an adjustment to remove the provision for rate refunds recorded by Empire from the starting point in this case, because the refund amount does not pertain to the Missouri jurisdiction.

Staff Expert/Witness: Ashley R. Sarver

B. Southwest Power Pool ("SPP") Revenues and Expenses

1. SPP Transmission Revenues

Empire receives revenues from the Southwest Power Pool ("SPP") to reimburse it for costs associated with transmission of electricity to other SPP members. Staff reviewed the monthly amount of revenues received from SPP since November 2010 for any trends in the data which would indicate that a revenue amount other than the test year revenue would be appropriate to include in the cost of service. Staff's review indicates that the total amount of SPP revenues received in the period of October 2014 through September 2015, which is the end of the update period in the case, is the most appropriate amount to use to normalize the SPP transmission revenues.

Staff Expert/Witness: Amanda C. McMellen

2. SPP Transmission Expenses

The SPP is a not-for-profit, regional transmission organization ("RTO") which maintains functional control over the transmission assets of its members and provides transmission service through its Federal Energy Regulatory Commission ("FERC") approved open access transmission tariff ("OATT"). SPP's costs of providing transmission service must be recovered from its member companies, including Empire. Staff recommends that the most current data for the twelve months ending September 2015 be used in determining the SPP annualized transmission expense amount to reflect in Empire's cost of service.

Staff Expert/Witness: Amanda C. McMellen

3. Ancillary Services Market Revenue and Expense

Empire began participating in SPP's Ancillary Services Market ("ASM") in March 2014. Empire entered the ASM to acquire ancillary services for its retail load and also to be able to provide these services to other SPP members from its own generation when available. Ancillary services generally refers to the services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system.[68] Staff has annualized test year ASM revenue and expense levels by using data for the 12 months beginning October 2014 through September 2015, which is the end of the update period in this case. Staff will continue to review Empire's ASM transactions as additional information becomes available throughout the true-up period.

Staff Expert/Witness: Amanda C. McMellen

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[68] As defined, per the glossary on the SPP website.

4. Miscellaneous SPP Related Revenues and Expenses

Empire also received certain miscellaneous revenues and incurred expenses as a result of participating in SPP's Integrated Market ("IM") beginning in March 2014. Staff has annualized these revenues and expenses by using data for the 12 months beginning October 2014 through September 30, 2015, which is the end of the update period in this case. Staff will continue to review these miscellaneous revenues and expenses as additional information becomes available through the true-up period.

Staff Expert/Witness: Amanda C. McMellen

5. Off-system sales revenue and expense

Off-system sales ("OSS") is the difference in value between the energy Empire sells through the SPP IM and the energy Empire purchases through the SPP IM to serve its native load. In Staff's fuel model run, Empire generated $17.8 million in sales and purchased $41.6 million of energy through the IM, resulting in net purchased power expense of $23.8 million.

Staff Expert/Witness: Amanda C. McMellen

C. Fuel and Purchased Power

1. Fixed Costs

Staff does not calculate within its fuel model those fuel and purchased power costs that do not vary directly with the amount of fuel burned. These costs are determined separately. The non-variable fuel costs included in fuel expense are typically referred to as fuel adders, described in the section below. The non-variable purchased power costs are referred to as capacity charges and these costs are annualized separately from purchased power energy costs.

Staff Expert/Witness: Keith D. Foster

a. Fuel Adders

The costs of fuel adders are determined separately from fuel model costs and are added to the level of fuel expense calculated by the model to determine overall fuel expense. The fuel adders in this case are natural gas transportation costs and freeze treatment costs for coal deliveries. Staff annualized the natural gas transportation expense based on Empire's current contractual obligations with Southern Star which began on January 1, 2010. In regard to freeze treatment costs, all Powder River Basin ("PRB") western coal delivered by rail to Asbury may be subject to being sprayed with a side release for freeze conditioning during the winter months. However, Staff could not confirm the treatment was being applied consistently in order to determine an annualized cost. Therefore, Staff used the actual costs for freeze treatment incurred for the twelve months ending September 30, 2015 (the update period), to add to the total fuel costs.

Staff Expert/Witness: Keith D. Foster

b. Purchased Power – Capacity Charges

In addition to its ownership interest in the Plum Point unit through Plum Point Energy Associates, LLC, Empire has contracted for a reservation of an additional 50 MW capacity from Plum Point through a purchased power contract. For this 50 MW of power, Empire pays a fixed component and an energy component. The fixed amounts Empire pays are referred to as capacity charges. Generally, there is an amount for Plum Point operation and maintenance costs included within the energy charge. The fixed component is paid as a "demand charge," generally on a monthly basis, regardless of the level of power actually purchased. This amount is for the "right" to purchase the power in much the same way that natural gas utilities purchase reservation of capacity from pipelines through reservation payments. The demand charges are intended to cover part of the fixed expenses of operating a generating facility.

Staff's adjustment to purchased power expense in this case annualizes demand charges for Empire's Plum Point Purchase Power Agreement.

Staff Expert/Witness: Keith D. Foster

c. Fuel Prices

Generally, Staff computed its level of fuel expense using prices and quantities contracted by Empire for delivery in 2016, including prices and quantities agreed to in fuel contracts that will become effective as of January 1, 2016, (with one exception described in the "Coal Prices" section below) and for current freight contracts. These fuel prices include prices for coal, natural gas, and oil, as well as associated transportation charges.

Staff Expert/Witness: Keith D. Foster

i. Coal Prices

Staff determined its coal price by generation facility based on a review and analysis of Empire's current coal purchase and coal transportation contracts. Staff's recommended PRB coal prices reflect Empire's actual contracted coal purchase prices in effect at January 1, 2016, and a 12-month average of transportation costs incurred through the update period, September 30, 2015. Staff's local bituminous coal price reflects Empire's actual contracted coal purchase price in effect at January 1, 2015. According to Empire, they are not purchasing this coal in 2016, but are using what remains on the ground. For the Plum Point unit, Staff's recommended coal prices reflect the actual contracted coal purchase and transportation prices in effect for 2016. For the Iatan 1 and 2 units, Staff's recommended coal prices reflect KCPL's projected weighted average contracted coal purchase and transportation prices for 2016.

Staff Expert/Witness: Keith D. Foster

ii. Natural Gas Prices

The natural gas price recommended in this case by Staff of $3.25 per MMBtu is composed of two components: hedged and non-hedged ("spot") prices. Staff calculated the non-hedged component of natural gas prices using a twelve-month weighted average of Empire's actual commodity cost of natural gas purchased on the spot market during the twelve months ending September 30, 2015. The weighted average price for the non-hedged component is $2.875 per MMBtu. Staff calculated the hedged component of natural gas costs by applying a weighted average for the actual hedged purchases contracted for at September 30, 2016, that is applicable to Empire's forecasted gas needs for the twelve months ending September 30, 2016. The weighted average price for the hedged component is $3.495 per MMBtu. Staff weighted the hedged gas price at 60% of its overall gas price recommendation, as Empire has contracted to meet approximately 60% of its projected natural gas usage from October 1, 2015, through September 30, 2016, with hedged gas supplies. Empire's natural gas transportation costs are annualized and normalized separately as a part of fuel adders.

Staff Expert/Witness: Keith D. Foster

iii. Fuel Oil Prices

Staff used a weighted average price of 1,831.04 cents per MMBtu to determine the fuel oil cost input in the fuel model in this case. Staff calculated this weighted average price by: (1) converting each month's number of barrels purchased over a 13-month period into gallons; (2) dividing a total month's purchase in gallons by that month's total purchase costs to derive an average monthly price per gallon; (3) summing the totals for the 13-month period to calculate a weighted 13-month average cost per gallon which, in this case, is $2.552471; and (4) converting this per gallon price into the cents per MMBtu, 1,831.04. Empire burns fuel oil mainly as a secondary fuel or, in some instances, for flame stabilization. Empire does maintain onsite storage at its various facilities in sufficient capacity that only occasional purchases are necessary. As a result, Empire does not contract for or hedge oil costs.

Staff Expert/Witness: Keith D. Foster

2. Losses

System energy losses largely consist of the energy losses that occur in the electrical equipment (*e.g.*, transmission and distribution lines, transformers, etc.) between Empire's generating sources and its customers' meters. In addition, small, fractional amounts of energy that is either diverted (stolen) or unmetered (unmetered usage) are included as system energy losses.

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

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

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

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

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

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

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

Staff calculated the loss percentage of Empire's system, for the twelve months ending September 2015, as 6.24% of NSI. Staff witness Seoung Joun Won used this loss percentage in the development of hourly loads used in Staff's fuel model.

Staff Expert/Witness: Alan J. Bax

3. Variable Costs

Staff estimates Empire's variable fuel and purchased power expense to be $113,411,072 for the twelve months ending September 31, 2015.

Staff uses the Plexos production cost model to perform an hour-by-hour chronological simulation of a utility's generation and power purchases. Staff uses this model to determine annual variable cost of fuel and net purchased power energy costs and fuel consumption necessary to economically meet a utility's load within the operating constraints of the utility's resources used to meet that load. These amounts are supplied to Auditing Department Staff who use this input in the annualization of fuel expense.

Staff used market prices in its fuel model dispatch to simulate Empire's operations in the SPP's IM. The price for energy in the IM dictates the amount of energy Empire sells in the IM. Consequently, Staff's fuel run dispatches Empire's generation to match Empire's load, thus simulating how the SPP would dispatch generation if it were being dispatched into the SPP IM based on prices set by the SPP's regional load requirements.

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.

Staff calculated the following inputs for use in the model: fuel prices, firm purchased power contract specifications, spot market purchased power prices and availability, hourly NSI, and unit planned and forced outages. Staff relied on Empire's responses to data requests, and data Empire supplied to comply with 4 CSR 240-3.190, for the characteristics of each generating unit; for example: capacity of the unit, unit heat rate curve, primary and startup fuels, ramp-up rate, startup costs, and fixed operating and maintenance expense. Information from Empire'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: Shawn E. Lange

4. Planned and Forced Outages

Planned and forced outages are infrequent in occurrence, and variable in duration. In particular, forced outages are unplanned and can happen at any time. In order to capture this variability, Empire generating unit outages were normalized by averaging the eleven years ending October 2015 of actual values taken from responses to data requests, and data Empire supplied to comply with 4 CSR 240-3.190.

Staff Expert/Witness: Shawn E. Lange

5. Energy Sales and Purchases

Staff used market prices in its fuel model dispatch to simulate Empire's operations in the SPP's IM. The price for energy in the IM dictates the amount of energy Empire sells in the IM. Consequently, Staff's fuel run dispatches Empire's generation to match Empire's load, thus simulating how the SPP would dispatch generation if it were being dispatched into the SPP IM based on prices set by the SPP's regional load requirements.

Staff Expert/Witness: Shawn E. Lange

6. Capacity Contract Prices and Energy

Capacity contracts are contracts entered into between electric providers for a specific amount of capacity (megawatts) and/or a maximum amount of hourly energy (megawatthours). Prices for the energy from these capacity contracts are based on either a fixed contract price or the generating costs of providing the energy. Empire's capacity contracts include the Elk River and Meridian Way Wind contracts, and the Plum Point contract.

Empire's actual hourly contract transaction prices were obtained from the data Empire supplied to comply with 4 CSR 240-3.190 and were used by Staff to calculate each contract's average monthly prices.

Staff Expert/Witness: Shawn E. Lange

7. Normalized Net System Input ("NSI")

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

Due to the presence of significant air conditioning and electric space heating in Empire's service territory, the magnitude and shape of Empire's NSI is directly related to daily temperatures. To normalize NSI, Staff used actual and normal daily temperatures provided by Staff witness Seoung Joun Won in its analysis. The actual daily temperatures for the update period, twelve months ending September 30, 2015, differed from normal daily temperatures. Therefore, to reflect normal weather, daily peak and average net system loads are each adjusted independently, but using the same methodology.

Daily average load is the summation of the hourly load for the day divided by twenty-four hours. Daily peak is the maximum hourly load for the day. Staff uses separate regression models to estimate both (1) a base component, which is allowed to fluctuate across time as non-weather factors, and (2) a weather sensitive component, which measures the response to daily fluctuations in weather for daily average loads and peak loads. Independent regression models are necessary because daily average loads respond differently to weather than peak loads. The models' regression parameters, along with the difference between normal and actual cooling and heating measures, are used to calculate weather adjustments to both the average and peak loads for each day. The adjustments for each day are added respectively to the actual average and to the peak loads of each day. The starting point for allocating the weather-normalized daily peak and average loads to the hours is the actual hourly loads for the year being normalized. A unitized load curve[69] is calculated for each day as a function of the actual peak and average loads for that day. Staff uses the corresponding weather normalized daily peak and average loads, along with the unitized load curves, to calculate weather normalized hourly loads for each hour of the year.

This process includes many checks and balances, which are included in the spreadsheets that are used by Staff. In addition, the analyst is required to examine the data at several points in the process. For more information, the process is described in greater detail in the document *Weather Normalization of Electric Loads, Part A: Hourly Net System Loads.*[70]

After weather-normalizing and annualizing usage for Empire's Missouri jurisdictional retail customer classes is completed, weather-normalized wholesale usage, as well as any non-Missouri jurisdictional 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 Missouri jurisdictional normalized revenues.

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

Staff Expert/Witnesses: Shawn E. Lange and Seoung Joun Won, Ph.D.

8. Purchased Power Prices

Staff's fuel model requires a set of spot market power prices for each hour in the model. Staff analyzed hourly day-ahead SPP IM locational marginal power prices from the onset of the

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

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

IM on March 1, 2014, through September 30, 2015, to determine monthly average peak and off-peak pricing at the Empire generator nodes and the Empire load node.

Staff updated the set of purchased power prices used in the final Staff EMS run from the previous rate case based on the public data available on the SPP website through September 30, 2015. Staff will update this set of purchased power prices using the SPP IM data through March 31, 2016.

Staff Expert/Witness: Erin L. Maloney

9. Entergy Transmission Contract

Empire has a contract with Entergy Solutions, Inc., for Firm Point-to-Point Transmission Service to transmit power generated from the Plum Point Energy Station to Empire. Staff included an adjustment that annualizes the cost of this service at the current contract rate effective September 30, 2015.

Staff Expert/Witness: Jermaine Green

D. DEPRECIATION

1. Depreciation Rates

In the recent KCP&L, KCP&L-GMO, and Ameren Missouri cases, Case Nos. ER-2010-0355, ER-2010-0356, and ER-2010-0036, respectively, the Commission accepted the use of the life span method and remaining life technique for developing depreciation rates. In the case at hand, Staff performed a depreciation study using these methods for Empire's production accounts, which resulted in the depreciation rates for production plant accounts set out in Schedule JAR(DEP) – d1. Staff performed this depreciation study using the same depreciation data set that Empire provided to its depreciation consultant.

Staff recommends for the Transmission, Distribution, and General Plant accounts the continued use of Whole Life Mass Asset depreciation rates as set out in Schedule JAR(DEP) - d1. Mass asset accounts differ from unit property accounts in that they represent many similar units rather than a distinct entity. When a unit under one of these accounts is retired, such as a meter, pole, or section of conductor, it is usually replaced with another unit with similar life characteristics. Though individual units will retire at a particular time, collectively the service life is indefinite because the units are of different ages and they retire after different lifespans because of factors that are essentially random such as manufacturing variances, location, user characteristics, weather, or accidents. In such cases, actuarial methods are used to project future retirements based on the history of the account. This approach was used for these accounts in previous Empire cases as well as in the study submitted by Empire's depreciation consultant.

2. Stopped Depreciation Accrual/Set Depreciation Rate to 0 Percent

In Staff's review of Empire's depreciation study, Staff found depreciation rate recommendations of 0 percent for five accounts on a going-forward basis. These accounts are: State Line Combined Cycle plant account 342 Fuel Holders, State Line Combustion Turbine account 341 Structures and Improvements, Energy Center Units 1 and 2 accounts 342 Fuel Holders, account 344 Generators, and account 346 Miscellaneous Power Equipment. Staff submitted nine data requests related to the recommendation of 0 percent depreciation rates. Empire's responses indicate that it is setting depreciation rates to 0 percent for accounts where reserves are equal to or higher than original cost. This is not the first time Staff has found that Empire has prematurely stopped depreciation accrual on an account or specific asset.

In Case No. ER-2011-0004, Robinett Surrebuttal, Staff identified that the sale of one of Empire's unit trains had been improperly handled and needed additional investigation. In Case No. ER-2012-0345, Staff investigated that unit train and made the following statement in the Cost of Service Report for Case No. ER-2012-0345:

> The second issue related to the steel unit train at the Asbury generating facility is that the Company stopped recording accrual of depreciation expense on the unit train from April 2007 through November 2007 when the unit train was sold. The Company continued to collect depreciation during the entire time of the lease when the Company was receiving income from a non-utility party. The Company fully collected the original cost of the unit train in March of 2007. In April of 2007 the Company stopped accumulating depreciation on the unit train, which would mean the Company was then collecting those dollars built into rates associated with the unit train depreciation expense as profit rather than booking an accrual to accumulated depreciation reserves, as the Commission previously ordered in Case No. ER-2005-0470. Staff recommends an adjustment to the depreciation reserves for

account 312 with a total Company addition of $248,137 for stopped depreciation accrual related to the eight (8) months prior to the sale of the unit train.[71]

Empire, as part of a *Stipulation and Agreement* in Case No. ER-2012-0345, agreed to make the reserve adjustments to properly reflect the sale and stopped depreciation accrual of the unit train at the Asbury facility to Asbury account 312 Boiler Equipment.

In the case at hand, Case No. ER-2016-0023, Staff calculated and recommends $3,082,367 of adjustments to depreciation reserves to reflect depreciation accruals that should have been booked during the period when depreciation rates were set to 0 percent. However, because of issues transitioning from paper to electronic records, Staff is uncertain of all of the accounts for which Empire has been using 0 percent depreciation rates and of the total shift that should occur. Staff is currently aware of 14 accounts or subaccounts that have stopped accruals for differing lengths of time since 2005. Only two accounts that Staff is currently investigating appear to have appropriate accruals; however, the investigation is ongoing and Staff may update its position regarding these accounts following its completion. The accounts that appear to have appropriately ceased to accrue depreciation are accounts 314 and 316 for Riverton Units 7 and 8. All of the plant has been retired so no accrual would be taking place. However, if the Company changed the depreciation rates for these accounts to zero then that treatment was incorrect. Here is the current list of accounts where depreciation accruals have stopped for a period of time since 2005:

Riverton Units 7 and 8 accounts 314 and 316;
Energy Center Units 1 and 2 accounts 342, 344, and 346;
State Line CT accounts 341 and 346;
State Line CC account 342;
Iatan 1 account 316I;
Iatan Common accounts 314IC, 315IC, and 316IC;
Transmission account 352I related to Iatan; and
Transmission Account 354 Towers and Fixtures.

Staff calculated the adjustments for depreciation reserves for the affected accounts. Staff recommends adjustments that total $3,082,367. The adjustments are all positive adjustments to reserves for the affected accounts and are as follows:

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[71] Case No. ER-2012-0345, Staff Cost of Service Report, page 100, line 26 -page 101, line 5, EFIS Item 123 filed 11/30/2012.

ESTIMATED ACCRUED DEPRECIATION ADJUSTMENTS
EMPIRE DISTRICT ELECTRIC COMPANY
ER-2016-0023
2005-2015

Plant/ Facility	Depreciation Group		Adjustment
Energy Center	342E	Fuel Holders, Producers & Access.	$480,325
	344E	Generators	$742,576
	345E	Accessory Electric Equipment	$60,329
	346E	Miscellaneous Power Plant Equipment	$537,488
		Plant Total	$1,820,717
Energy Center FT8	342FT	Fuel Holders, Producers & Access.	$3,354
Iatan	312IT	Boiler Plant Equipment	$15,724
	316IT	Miscellaneous Power Plant Equipment	$35,459
		Plant Total	$51,183
Iatan 2	316I2	Miscellaneous Power Plant Equipment	$526,273
Iatan Common	314IC	Turbogenerator Units	$2
	315IC	Accessory Electric Equipment	$25
		Plant Total	$27
Iatan Transmission	352I	Structures & Improvements	$25,213
	353I	Station Equipment	$11,339
		Plant Total	$36,552
Riverton	314R	Turbogenerator Units	$166,558
	315R	Accessory Electric Equipment	$94,621
	316R	Miscellaneous Power Plant Equipment	$24
		Plant Total	$261,203
Stateline	341S	Structures & Improvements	$227,197
	346S	Miscellaneous Power Plant Equipment	$85,345
		Plant Total	$312,542
Stateline CC	342C	Fuel Holders, Producers & Access.	$62,170
Transmission	354	Towers & Fixtures	$8,345
		GRAND TOTAL	$3,082,367

3. "Shortfall / Deficiency" for the Retirement of Riverton Units 7 and 8

Staff has reviewed the unrecovered reserves associated with the retirement of Riverton Units 7 and 8. Staff estimates that accounts related to Riverton Units 7 and 8 are under-recovered by $7.8 million. As the Company and Staff previously agreed in Case No. ER-2012-0345:

> Should the retirement of Riverton 7 or 8 create a reserve deficiency under Generally Accepted Accounting Principles (GAAP), the signatories agree to support a reasonable request by Empire for accounting authority pursuant to Accounting Standard 980 (FAS 71) to reallocate the depreciation reserve to cover the cost of removal of such plant.

Depreciation Staff recommends the following transfers of reserves:

DEPR GRP	FERC USOA DESCR	Adjustments
RIVERTON 7&8		
311R	Structures	$ 3,442,188
312R	Boiler Plant	$ 4,831,496
314R	Turbogenerators	$ 1,390,628
315R	Access. Electric	$ 410,252
316R	Misc. Equipment	-$ 41,047
IATAN 1		
316I	Misc. Equipment	-$ 436,275
ENERGY CENTER		
341E	Structures	-$ 697,697
342E	Fuel Holders	-$ 791,573
344E	Generators	-$ 3,894,864
346E	Misc. Equipment	-$ 2,046,394
STATE LINE UNIT 1		
341S	Structures	-$ 528,654
346S	Misc. Equipment	-$ 127,963
STATE LINE CC		
342C	Fuel Holders	-$ 1,510,097

Depreciation Staff is not recommending an amortization of the unrecovered reserve as requested by Empire. Staff instead recommends transferring reserves to cover the under recovered portion of Riverton Units 7 and 8. In addition to the reserve adjustments for reserve deficiency, Staff is recommending a 10% depreciation rate on the remaining assets related to Riverton steam production plant; this rate equates to approximately $300,000 of annual depreciation expense. Empire's depreciation study estimated the cost of removal for Riverton Units 7, 8, and 9 to be approximately $3 million. Staff's recommended transfer of reserves does not cover the full estimated cost of removal for Riverton Units 7, 8, and 9. Hopefully between the transfer of reserves and the continued depreciation or remaining steam assets, the reserve totals will contain close to the final costs to remove the retired plants.

4. Riverton 12 CC Estimated Depreciation Expense

Staff has calculated an approximation of the depreciation expense related to the conversion of Riverton Unit 12 to a combined cycle unit. The estimated plant balances Staff used to calculate the estimated depreciation expense for the conversion of Riverton are from Data Request No. 0019 from File No. EO-2014-0069. This conversion is expected to be placed into service and included as part of the true-up. Staff's projected depreciation expense for plant investment related to the conversion is an increase of Missouri Jurisdictional depreciation expense of $2,526,049. Staff's current depreciation rate recommendation for Riverton Unit 12 is based on Riverton Unit 12 as a combustion turbine unit, not as a combined cycle unit. Staff reserves the right to update depreciation rates related to Riverton Unit 12 conversion at the time of true-up in this case.

5. Recommendations

Staff recommends the Commission order the following:

1. The Commission order the depreciation rates for the production accounts requested by Staff in recognition of the Commission's Orders accepting the methods and assumptions used in the recent KCP&L, KCP&L-GMO, and Ameren Missouri cases ER-2010-0355, ER-2010-00356, and ER-2010-0036, respectively as shown in Appendix 3, Schedule JAR(DEP) - d1.

2. The Commission order Empire to use the depreciation rates for the transmission, distribution, and general plant accounts as shown in Appendix 3, Schedule JAR(DEP) - d1.

3. The Commission order Empire to book the adjustments to depreciation reserves related to stopped depreciation; reserve adjustments found in table on page 94 of Staff Cost of Service Report.

4. The Commission order Empire to perform the reserve transfers proposed by Staff to cover the reserve short fall at Riverton Units 7 and 8; Staff

recommended transfers are found in table on page 95 of Staff Cost of Service Report.

5. The Commission not authorize the amortization recommended by Empire to recover the under recovery of reserves at Riverton Units 7 and 8.

Staff Expert/Witness: John A. Robinett

E. RIVERTON 12 O&M TRACKER

On January 1, 2015, Empire entered a Long-term Maintenance Contract with Siemens for the maintenance of Unit 12 at the Riverton plant. This contract is similar to the agreement at Empire's State Line Combined Cycle facility in which Siemens conducts maintenance service for the turbines, which are required to run for a specified number of hours. The cost breakdown of this agreement with Siemens includes an initial fee, an hourly rate based on the variable equivalent operating hours ("EOH"), and an annual fixed fee.

In Empire's last rate case, No. ER-2014-0351, Staff recommended that a tracker be established with a base annual amount of ** __________ ** Missouri Jurisdictional, for Riverton 12 maintenance expenses. This tracker mechanism was agreed to in the *Non-Unanimous Stipulation and Agreement* in Case No. ER-2014-0351. The fluctuations of Riverton 12 O&M expenses above or below this annual base level of ** __________ ** have been recorded as a regulatory asset/liability. Staff's methodology for determining the Riverton 12 tracker base was based on Empire's projected equivalent operating hours at the contracted rate. Staff did not include 2,475 equivalent operating hours that the Company "anticipated" for the commissioning of the new Riverton 12 unit as a combined cycle generation unit in the tracker base, as it was Staff's position that these hours represent a one-time cost and should not be included in ongoing expense levels or in a tracker mechanism. Instead, these costs should be treated as a capital item.

In this current case, Empire is proposing to rebase the Riverton 12 O&M tracker from ** ______________________ ** of annual expense based on a new estimated equivalent operating hours calculation. It is Staff position that the tracker base level should remain at $2.7 million until there is a sufficient operational history to determine a true estimate. Staff will perform a review of the actual O&M expenses incurred by Riverton 12 during the true-up phase of this case to determine if a rebase is reasonable at that time.

Staff Expert/Witness: Jermaine Green

F. Payroll and Benefits

1. Payroll, Payroll Taxes and 401(k)

Staff adjusted Empire's test year payroll expense to reflect an annualized level of payroll, payroll taxes, and 401(k) benefit costs as of September 30, 2015. Base payroll was calculated by multiplying employee levels at September 30, 2015, by the then-current appropriate salary or wage rate to derive the annualized payroll cost. Overtime payroll for Empire was calculated for each full-time hourly employee based upon: (1) an overtime percentage computed for non-union five-year average of overtime hours actually incurred, (2) multiplying that by the current average rate paid for overtime as of September 30, 2015, and (3) dividing the product by Staff's *pro forma* base without inclusion of overtime hours for storms related to emergency events in which Empire assisted other utilities and the May 2011 Joplin tornado. In regards to the Joplin tornado, the Commission granted Empire an Accounting Authority Order ("AAO") to defer all incremental O&M costs associated with the tornado. Any overtime costs incurred as a result of this tornado needed to be removed in order to avoid a situation where Empire could potentially recover those costs twice in rates.

An allocation rate for distributing the payroll adjustment to Empire's electric operations was determined by using the percentage of Empire's electric operating payroll costs to its total payroll costs (including electric construction, water operations, etc.). After allocation between expense and construction, the adjustment for payroll was distributed by Federal Energy Regulatory Commission Uniform System of Accounts ("FERC USOA") based upon the actual distribution experienced by Empire for the twelve months ending April 30, 2014, which was established in the last rate case, No. ER-2014-0351. Staff's Accounting Schedule 10, Adjustments to the Income Statement, reflects all payroll adjustments, segregated by FERC USOA Accounts, to reflect Staff's total adjustment required to restate the test year payroll to an annualized level as of September 30, 2015.

Staff calculated payroll taxes based upon September 30, 2015, wage levels and current tax rates. This included Federal Unemployment Taxes ("FUTA"), State Unemployment Taxes ("SUTA"), and Federal Insurance Contributions Act ("FICA") tax. In addition, FICA payroll taxes were computed for allowable non-earnings based incentive payments incurred in the test year. The Company's 401(k) benefit costs were annualized by applying Empire's actual 401(k) match rate for each employee to the annualized payroll as of September 30, 2015.

Staff Expert/Witness: Jermaine Green

2. Incentive Compensation

Staff reviewed Empire's portfolio of incentive compensation plans offered to its employees. Based upon this review, Staff is proposing adjustments to the Company's incentive compensation expenses related to the Management Incentive Compensation Plan ("MIP"), lump-sum payments offered to certain employees called "Lightning Bolts," and equity incentive compensation offered to the Company's executives. These disallowances are not stated as separate income statement adjustments, but are embedded within Staff's previously described total payroll adjustments.

a. Management Incentive Compensation Plan ("MIP")

Empire's MIP program offers awards to Empire senior officers for the achievement of certain pre-set goals. In 2014, each senior officer had a list of goals pertaining to areas such as expense control, capital markets, regulatory performance, customer service, project completion, operations, financial performance, corporate governance, and safety. Each of these goals was given a specific performance measure and weighting, thus assigning a target cash payout. The amount of the award determination would have been based upon attainment of a specific performance level by the senior officer:

Threshold (50% of target payout)
Target (100% target payout)
Maximum (200% of target payout)

If the results for a specific goal were below the threshold, the senior officer would not have received an MIP award related to that specific goal. If the results were at or above the level set for the maximum goal, the senior officer would have received double the target MIP award for that specific goal.

In order to determine the appropriate amount to include for the MIP in this case, Staff performed a review of all the incentive metrics used to measure each individual goal and the actual award received. Staff then disallowed all the actual awards paid out to Empire's executives and department heads associated with the performance measure of meeting earnings per share targets. In Staff's review of the incentive metrics, it was determined that the earnings per share performance measure accounted for 20.72% of the total incentive award paid out. Any incentive goals associated with enhancing the value of a utility's stock price and the achievement of these goals benefits Empire's shareholders, not Empire's ratepayers; therefore, Staff removed this expense from inclusion in rates.

b. Lightning Bolts

Empire's "Lightning Bolts" program offers one-time incentive payments in the nature of bonuses to certain employees. Staff has disallowed the cost of these discretionary bonuses paid in 2015. The Commission's *Report and Order* in Case No. ER-2006-0315 adopted Staff's recommended disallowance of short-term incentive compensation tied to discretionary bonuses that are unsupported by well-defined goals and for which the criteria for granting awards is not known to the employee in advance.

c. Equity Incentive Compensation

In Empire's past rate cases, Staff also recommended a disallowance of long-term stock incentive compensation awarded to Empire's executive management, which results in the issuance of stock annually that is considered to be part of the senior officer's total compensation. The senior officers do not have any specific goals to meet in order to be granted these stock options. Awarding these stock options benefits Empire's shareholders, not Empire's ratepayers. Additionally, unlike other expense recognition in the income statement, expense recognition for equity-based incentive compensation does not result in a cash outlay by Empire. Staff has eliminated stock options recognized as an expense in this case consistent with the Commission's *Report and Order* in Case No. ER-2006-0315.

Staff Expert/Witness: Jermaine Green

3. Payroll Benefits

Empire currently offers its employees Dental, Vision, Healthcare, and Life Insurance benefits. Staff performed an analysis of the employee benefit costs included in Account 926 from the general ledger. Staff annualized each expense by examining the individual costs over a three year period to determine the appropriate amount to include for each expense. Staff performed a three-year average through the update period to annualize these expenses ending September 30, 2015.

Staff Expert/Witness: Jermaine Green

4. FAS 87 and FAS 88 Pension Costs

In Case No. ER-2004-0570, the Staff, Empire and other parties entered into a *Stipulation and Agreement as to Certain Issues*, addressing, among other items, the ratemaking treatment for annual pension cost under Financial Accounting Standard No. 87 ("FAS 87"). This agreement, and thus treatment of annual pension cost, was later modified by each of the later *Stipulation and Agreement as to Certain Issues* entered into in Case Nos. ER-2006-0315, ER-2008-0093, ER-2010-0130, ER-2011-0004, ER-2012-0345, and ER-2014-0351. (Collectively, Staff will refer to the *Stipulations and Agreements* regarding pension expense ratemaking from the 2004 rate case to current as the "Pension Agreements.") These above-referenced Pension Agreements provide for Empire to generally have its pension rate allowance set equal to its most current annual level of pension expense as calculated under FAS 87. Furthermore, these agreements established a tracker mechanism for Empire's pension expense, in which any excess or deficit in the Company's pension rate allowance, as compared to its ongoing levels of FAS 87 expense, is to be treated as a regulatory asset or liability. The resulting pension tracker regulatory asset or pension tracker regulatory liability is then to be included in Empire's rate base, and amortized as an addition or reduction to pension expense over a five-year period.

Pension cost under FAS 87 has been reflected in Staff's income statement for this case in a manner consistent with the ratemaking treatment agreed upon by the signatories to all of the stipulation and agreements approved by the Commission in Empire's last seven electric rate cases. Empire's rate base, as determined by the Staff, includes the FAS 87 Regulatory Asset, which represents the cumulative difference between FAS 87 pension costs recovered in rates and FAS 87 pension costs recognized in the financial statements between rate cases.

Additionally, Staff has included a prepaid pension asset ("PPA") in rate base in the amount of $22,169,990. The PPA represents the cumulative amount of contributions in excess of actual costs as of September 30, 2015. These contributions were made to prevent the pension plan from becoming "at-risk" as defined under the Pension Protection Act, and to meet the obligations of the Pension Benefit Guarantee Corporation. Staff's cost of service does not include an amortization of this PPA. Future contributions to the pension plan will be reduced by this PPA amount.

Empire's pension costs in this case were based upon the Company's actuary report, Exhibit 1 of Empire's 2015 Pension Expense and workpapers. Staff will update its current projection of pension costs, tracker balance and amortization in its True-Up testimony. The results of the Staff's review to date of Empire's pension costs are as follows:

1. The Company's ongoing FAS 87 expense recognized in rates in this case is $7,664,807.

2. Empire has under-recovered its FAS 87 expense in rates compared to its actual level of expense since the Company's last rate case. The balance in the Regulatory Asset account at September 30, 2015, was $2,945,242, which is to be amortized over five years as an expense in the amount of $589,048

3. The amount to be included in rate base for Empire's ongoing pension expense tracker mechanism is $2,945,242, as noted above.

4. An amount of $22,169,990 is included in Empire's rate base as a prepaid pension asset.

Staff Expert/Witness: Paul R. Harrison

5. FAS 106 – Other Post-Employment Benefit Costs ("OPEBs")

In Case No. ER-2006-0315, the signatory parties entered into a *Non-Unanimous Stipulation and Agreement as to Certain Issues*, addressing the ratemaking treatment for annual other post-employment benefit costs (also known as "OPEBs") under Financial Accounting Standard No. 106 ("FAS 106"). OPEBs primarily relate to medical benefits owed by Empire to Company retirees. The 2006 agreement was later modified by the *Stipulation and Agreement as* *to Certain Issues* reached in Case No. ER-2008-0093, ER-2010-0130, ER-2011-0004, ER-2012-0345, and ER-2014-0351. (Collectively, Staff will refer to the *Stipulations and Agreements* regarding OPEB expense ratemaking from the 2006 rate case to current as the "OPEB Agreements.") These OPEB Agreements were intended to ensure that the amount collected in rates for OPEBs were based on the FAS 106 cost recognized by the Company for financial reporting purposes, using a methodology similar to that used to determine FAS 87 pension cost. In addition, the OPEB Agreements were intended to ensure that Empire contributed the full amount of the OPEB expenses it collected in rates into an external trust fund. The OPEB Agreements also called for the use of a OPEBs tracker mechanism to quantify the difference over time in the OPEBs rate allowance provided to the Company, and the Company's annual actual OPEBs expenses under FAS 106.

In this case, Staff has complied with the terms agreed upon by the signatories to OPEB Agreements approved by the Commission in Empire's last six electric rate cases for ratemaking treatment of OPEBs costs. Empire's OPEB costs in this case were based upon the Company's actuary report, Exhibit 3 of Empire's 2015 OPEB expense and workpapers. Staff will update the OPEB costs, tracker balance and amortization in its True-Up testimony. The results of Staff's review of Empire's OPEB costs are as follows:

1. The Company's ongoing FAS 106 cost recognized in rates in this case is $2,731,018.

2. Empire has over-recovered its FAS 106 expense in rates compared to its actual level of expense since the Company's last rate case. The balance in the Regulatory Liability account as of September 30, 2015, was ($819,451), which is to be amortized over five years as a reduction to expense in the amount of ($163,890).

3. Rate base is reduced by the level of regulatory liability associated with Empire's ongoing OPEBs tracker mechanism, $819,451 as noted above.

Staff Expert/Witness: Paul R. Harrison

6. Supplemental Executive Retirement Plan ("SERP")

Certain management employees receive benefits under Empire's Supplemental Employee Retirement Program ("SERP"). The provisions of FAS 87 are used to calculate the annual financial reporting expense accrual for this plan. Due to the fact that the benefits from this retirement program are not available to a broad range of employees, the Internal Revenue Service ("IRS") designates this program as a "non-qualified" plan. In a non-qualified plan, the expense is not "pre-funded" and only the amounts paid to beneficiaries are tax deductible. Therefore, Staff's policy has been to limit utilities' rate recovery of this item to actual benefit payments to employees, if reasonable. Staff used the five-year average ending September 30, 2015, of actual payments made to determine the annual cost of the SERP for inclusion in rates for this case.

Staff Expert/Witness: Paul R. Harrison

G. Maintenance Normalization Adjustments

Empire's maintenance expenses for its generating facilities (production stations) tend to fluctuate from year to year, since unscheduled outages occur at irregular and unpredictable times, and major planned outages do not occur annually. Each maintenance account was reviewed and analyzed separately for each production station. The production facilities examined included Iatan 1, Iatan 2, Iatan Common, Asbury, Riverton, State Line Combined Cycle, State Line 1, Energy Center, Ozark Beach, and Plum Point. These units were examined individually because each of them is on a different maintenance cycle and to group them would have either overstated or understated the final annualized maintenance costs. These adjustments were then combined where possible in an effort to reduce the volume of adjustments.

The Staff's proposed production maintenance normalization adjustments pertain to Empire's non-labor maintenance costs only; labor maintenance costs are handled as part of the Staff's overall payroll adjustments.

1. Iatan 1

Staff noted the Iatan 1 production station is on a six-year major maintenance cycle. For that reason, Staff used a six-year average of maintenance costs to develop its adjustment for Iatan 1 maintenance expense. Empire owns only 12% of the Iatan 1 unit.

2. Asbury

The Asbury maintenance expense is based on a five-year overhaul schedule of the boiler and turbine. Staff's adjustment is based upon a five-year average of maintenance costs.

3. Riverton (Excluding Riverton Unit 12)

The Riverton maintenance expense is based on a five-year overhaul schedule of the boiler and turbine. Staff's adjustment is based upon a five-year average of maintenance costs.

4. State Line Combined Cycle ("SLCC") and State Line Common

The SLCC maintenance expense is based on a five-year overhaul schedule of the boiler and turbine. Empire owns 60% of the SLCC unit, with Westar Energy ("Westar") owning the remaining 40%. Staff subtracted 40% of SLCC expenses incurred in the period ended September 30, 2015, to adjust out Westar's portion of test year expenses. Staff then applied an adjustment based on a five-year average of Empire's portion of maintenance costs. Empire is responsible for 66.7% of the State Line Common maintenance expenses, while Westar Energy is responsible for the remaining 33.3%. Staff subtracted 33.3% of State Line Common expenses incurred in the test year amount, established in the last case ER-2014-0351, to adjust out Westar's portion of test year expenses. Staff then applied an adjustment based on a five-year average of Empire's portion of maintenance costs.

5. State Line 1

Empire has had a contract with Siemens group, related to the maintenance of this production unit, since June 29, 2001. The terms of the contract require Siemens to conduct maintenance service for the turbines, which are required to run for a specified number of hours per year. If a turbine does not meet the annual hours requirement, a credit is due to Empire from Siemens and if the turbine exceeds the hours, then the Company incurs additional costs from Siemens. The nature of this expense varies greatly from year to year and, therefore, Staff is recommending using a five-year average to normalize this expense. Staff subtracts the actual test year amount, established in the last case ER-2014-0351, from the five-year average to derive Staff's adjustment.

6. Energy Center and Ozark Beach

The Energy Center and Ozark Beach maintenance expense is based on a five-year overhaul schedule of the boiler and turbine. Staff's adjustment is based upon a five-year average of maintenance costs.

H. O&M Expenses for Iatan 2, Iatan Common, and Plum Point

Empire currently owns 12% of Iatan 2 and Iatan Common generating facilities and 7.52% of Plum Point. As of September 30, 2015, the end of the update period in this case, the Iatan 2 and Plum Point units each had five (5) years of operating experience. Accordingly, Staff used a five (5) year average of actual O&M expenses pertaining to Iatan 2, Iatan Common, and Plum Point to determine the normalized level of these expenses.

In Empire's last general rate case proceeding, Case No. ER-2014-0351, the parties agreed to terminate the tracker mechanism that had previously been used for Iatan 2, Iatan Common, and Plum Point O&M expenses. It was agreed that this tracker would end on July 31, 2015. Therefore, in this case, Staff analyzed the Iatan 2, Iatan Common, and Plum Point O&M costs beginning September 30, 2014, through July 31, 2015. For this time period, Staff then calculated the total O&M costs, including only the accounts identified in the computation of the base tracker amounts established in Case No. ER-2012-0345. Base tracker amounts were identified for Iatan 2, Iatan Common, and Plum Point. Staff then compared the total O&M costs from September 30, 2014, through July 31, 2015, to the base tracker amounts to determine the associated regulatory asset or liability for each plant. These new base tracker amounts were added to the pre-existing unamortized balances already in rate base. Staff recommends a three-year amortization of the excess costs over the base amount be used to set rates in this case. These balances will be updated as part of the true-up audit in this case, No. ER-2016-0023.

Staff Expert/Witness: Jermaine Green

I. Other Non-Labor Expenses

1. Customer Deposit Interest Expense

See the discussion in Section VIII. H., Rate Base-Customer Deposits.

Staff Expert/Witness: Jennifer K. Grisham

2. Property Tax Expense

Utility companies are required to file a valuation of their utility property with their respective taxing authorities at the beginning of each assessment year, which is January 1st.

Based on the information provided by the utility, the taxing authority will in turn send the company its "assessed values" for every category of the company's property. The taxing authority will then issue to the utility company a property tax rate later in the year. The final step in the process is when the taxing authority issues a property tax bill to the company late in each calendar year with a "due date" of December 31st. The billed amount of property taxes is based on the property tax rate applied to the previously determined assessed values of the utility's plant in service balances as of January 1st of the same year.

Staff determined its adjustment for property taxes by developing a property tax rate to be applied to total electric plant in service as of December 31, 2014. Staff used the Company's property tax rate included in their filing in this case. This property tax rate was then applied to total electric plant in service on December 31, 2014, to arrive at annualized property taxes. The annualized property tax expense was then subtracted from the property tax expense starting point in this case to derive the adjustment.

One minor difference in property taxes for the current rate is the treatment of the Plum Point Generating Unit ("Plum Point") located in Arkansas. The owners of the Plum Point unit, including Empire, have entered into an agreement with the City of Osceola, Arkansas; Mississippi County, Arkansas; Osceola School District No. 1 of Mississippi County, Arkansas; and Mississippi County Community College District of Arkansas, to make an annual Payment in Lieu of Taxes ("PILOT") instead of paying property taxes on the Plum Point unit in the normal manner. A PILOT agreement allows the owners of the Plum Point unit to pay one flat amount of property taxes on the Plum Point unit for 30 years with the potential for an extension at the end of the 30-year term, regardless of any additions or retirements made to the unit since its in-service date. To appropriately calculate the overall property tax amount for Empire, the amount of Empire's share of the Plum Point plant had to be subtracted from total plant in service so as not to be included in the development of the annualized property taxes. The set amount of PILOT taxes that Empire has agreed to pay for Plum Point was then added to the annualized property tax calculation to determine the total property tax adjustment.

Staff will update its recommended level of property taxes as part of the true-up audit in this proceeding.

Staff Expert/Witness: Ashley R. Sarver

3. Corporate Franchise Taxes

Prior to January 1, 2016, Empire paid a corporate franchise tax in order to conduct business in the State of Missouri. Staff applied an adjustment in the prior rate case No. ER-2014-0351 but with a 0% jurisdictional allocation factor the account (408.910) was set to zero. The State of Missouri eliminated the corporate franchise tax effective January 1, 2016. Therefore, Staff made no adjustment, leaving the account at zero.

Staff Expert/Witness: Keith D. Foster

4. Amortization Expenses

a. Amortization of Electric Plant

Staff reviewed all of Empire's amortization expense booked to Account 404000, Amortization-Limited Term Electric Plant. After reviewing this data, Staff made an adjustment to increase this expense to reflect the annualized amortization based on updated information through September 30, 2015 (as described earlier in Section VIII. F.).

Staff Expert/Witness: Jennifer K. Grisham

b. Amortization of Stock Issuance Costs

Staff has reviewed the Company's books and determined that the entire amount of the prior costs associated with issuance of common equity will be fully amortized prior to new rates being established in the current rate case. The issuance costs will be fully amortized as of April 2016. Therefore, the stock issuance expense amortizations have been eliminated from cost of service in this case.

Staff Expert/Witness: Ashley R. Sarver

c. Amortization of Ice Storm Costs

Empire booked ice storm amortizations in account 593599 from the other states in which it operates. Therefore, Staff made an adjustment to eliminate the amortized amount of the ice storm amortizations from other states that were included in the starting point in this case.

Staff Expert/Witness: Jennifer K. Grisham

5. Iatan Carrying Costs Amortization

Pursuant to earlier agreements, Empire deferred certain carrying costs (monthly debt and equity-derived carrying charges) and monthly deprecation for its Iatan 1 AQCS Account 182308 - Iatan Deferred Carrying Costs, Iatan 2 Account 182332 - MO IatanII Df Chg ER-2010-0130, and Plum Point Account 182331 - MO PlumPt Df Chgs ER-2010-0130. This deferral of carrying costs on the Iatan 1 AQCS, Iatan 2, and Plum Point investments was authorized under previous agreements, approved by the Commission. In Empire's Case No. ER-2012-0345, Staff recommended amortization of these carrying costs into cost of service using a composite amortization rate derived from dividing the total depreciation expense for each plant by the total plant balance for each plant. Staff used these composite rates and calculated amortization amounts of $84,729 for Iatan 1 AQCS, $44,828 for Iatan 2, and $1,987 for Plum Point. Staff used the same amortization amounts in this case.

Staff Expert/Witness: Keith D. Foster

6. Demand Side Management

a. DSM Programs

As part of Empire's Experimental Regulatory Plan, approved in Case No. EO-2005-0263 ("2005 Case"), Empire's Customer Programs Collaborative ("CPC") was ordered to include Staff, Public Counsel, Department of Natural Resources,[72] and other interested parties to advise Empire on the development, implementation, monitoring, and evaluation of demand response, energy efficiency, and affordability programs for Empire's Missouri customers.

As stipulated in the 2005 Case, the effective date of the initial rates that reflect inclusion of the Iatan 2 investment on customer's bills would terminate Empire's Experimental Regulatory Plan. On June 15, 2011, Empire's Experimental Regulatory Plan terminated as a result of the Commission's June 1, 2011, *Order Approving Global Agreement* ("2011 Order") in Case No. ER-2011-0004. Also as a result of the 2011 Order, Empire's CPC was terminated and the Demand-Side Management ("DSM") Advisory Group was created.

[72] Now the Missouri Department of Economic Development – Division of Energy.

In Empire's last general rate case, Case No. ER-2014-0351, the Commission ordered[73] that, "With the exception of the low-income weatherization program discussed below, ... Empire will continue its current energy efficiency programs, at current funding levels and with the current recovery mechanism, until Empire has an approved MEEIA[74] or until the effective date of rates in Empire's next general rate case."

Schedule BJF-d1 contains annual actual expenditures, budgets, and variances from budget for each of Empire's DSM programs for each of the past five (5) years. While six of Empire's seven DSM programs consistently under-perform when it comes to spending their annual budget and reaching annual energy and demand savings targets, respectively, the Commercial & Industrial Facility Rebate Program[75] ("C&I Program") overspends. The current quarterly funding level for the C&I Program is $103,500, with the total annual funding level equal to $414,000. However, for its C&I Program in 2015, Empire actually spent $225,765 in the first quarter, $187,714 in the second quarter, $305,359 in the third quarter, and $218,588 in the fourth quarter, for an annual total of $937,425 spent. This overspend of $523,425 for 2015 is primarily due to the flood of applications that Empire received for projects from trade allies taking advantage of the relatively high incentive Empire offers in its C&I Program. Empire's C&I Program incentive is based on a buy down to the lesser of a two (2) year payback or fifty percent (50%) of incremental costs. There has not been any independent evaluation, measurement and verification ("EM&V") of the C&I Program since 2009; there has never been a net-to-gross evaluation of the program.

Staff has reviewed Empire's DSM Programs tariff sheets. Upon review, Staff found numerous instances of outdated and incorrect information within Empire's DSM programs tariff sheets including: (1) multiple references to the CPC; (2) a reference to the website and sponsorship of the Missouri Department of Natural Resources for the Home Performance with ENERGY STAR® program; (3) program year and budget displayed only up through 2013; (4) references to "the end of 2014" that are no longer relevant, etc.

Staff Expert/Witness: Brad J. Fortson

[73] *Report and Order* filed June 24, 2015.

[74] Missouri Energy Efficiency Investment Act.

[75] The Empire District Electric Company, P. S. C. Mo. No. 5, Section 4, 3rd Revised Sheet No. 8a.

b. DSM Cost Recovery

Empire's Account 182318 contains costs of the Company's DSM programs that are in various stages of development and implementation. Staff participated in the previously authorized (and now expired) Customer Programs Collaborative ("CPC") and participates in the current authorized DSM advisory group established to assist Empire in the development of DSM programs. Based upon Staff's participation in these groups, as well as Staff's review of the costs in Account 182318, Staff has amortized the amounts incurred by Empire prior to the end of the its Regulatory Plan (June 15, 2011) over ten years and any amounts incurred after the end of the Regulatory Plan to date are amortized over a period of six years, consistent with the terms of the Commission's *Report and Order* in Case No. ER-2014-0351. Staff has removed the program expenditures from 2005 and 2006 since they will be expiring on December 31, 2016. The DSM costs include the payments to Empire's customers that participate in the programs.

Staff Expert/Witness: Ashley R. Sarver

c. Chapter 22 Electric Utility Resource Planning

On April 1, 2016, Empire's electric utility resource planning triennial compliance filing[76] will be filed with the Commission. The triennial compliance filing will play a key role in understanding Empire's long-term DSM strategy and whether the strategy will provide benefits for all customers.[77] Staff will review Empire's triennial compliance filing and may make specific recommendations concerning current DSM programs in rebuttal testimony to this case.

Staff Expert/Witness: Brad J. Fortson

d. MEEIA Filings

Empire filed its first MEEIA application on February 28, 2012, in File No. EO-2012-0206 and withdrew it on July 5, 2012. Empire filed a subsequent MEEIA application on October 29, 2013, in File No. EO-2014-0030; however, the procedural schedule was suspended on January 14, 2014, to allow additional time for technical conferences and settlement discussions. However, on July 24, 2015, Empire filed *Empire's Motion to Withdraw its MEEIA*

[76] 4 CSR 240-22.080(1) Filing Schedule, Filing Requirements, and Stakeholder Process.

[77] Section 393.1075.4 of the MEEIA statute.

Application and Request for this Docket to be Closed. On August 13, 2015, the Commission filed a *Notice of Dismissal* and the case was dismissed. To date, Empire has not filed another MEEIA application.

Staff Expert/Witness: Brad J. Fortson

7. Low Income Programs

Empire currently has a program called Low-Income New Homes which works with local non-profit organizations, such as the Habitat for Humanity and local government community development organizations to provide financial incentives for increased energy efficiency in the building shell insulation and for high-efficiency central air conditioners, heat pumps, refrigerators and lighting fixtures.

In addition to the Low-Income New Homes program, Empire also offers other programs to assist the elderly and disabled. The first program is entitled Empire's Action to Support the Elderly ("EASE"). EASE allows Empire to wave late penalties and deposits, adjust due dates and notify third parties when an account becomes delinquent. Finally, Empire jointly works with Crosslines Churches in Joplin and the voluntary donations of customers to offer Project Help. Project Help is an assistance program created to meet emergency energy-related expenses of the elderly and/or disabled residents in Empire's electric service area.

Staff has reviewed the programs and is not aware of any issues that need to be addressed in this case.

Staff Expert/Witness: Kory Boustead

a. Low Income Weatherization

The State of Missouri Low-Income Weatherization Assistance Program ("LIWAP") is administered by the Missouri Department of Economic Development, Division of Energy ("DED-DE") using federal, state, and utility funding. The DED-DE low-income weatherization program is administered locally by Community Action Agencies or other local agencies ("Weatherization Agencies"). The total amount of grants offered to a customer and customer eligibility is determined by federal LIWAP guidelines published by the U.S. Department of

Energy ("USDOE"). The funding focuses on measures that reduce electricity usage associated with electric heat, air conditioning, refrigeration, lighting, etc.

Empire began providing supplemental funding for the State of Missouri's federally funded LIWAP, subjected to the USDOE guidelines, as part of the *Stipulation and Agreement* in Case No. ER-2004-0570. Empire participates in a Demand Side Management Advisory Group ("DSMAG"), composed of the Public Service Commission Staff, the Office of the Public Counsel, DED-DE, and others to oversee the allocation of funds and review annual reports provided by Empire and the Weatherization Agencies, consisting of:

a) Program funds provided by Empire.
b) Amount of Program funds, if any, rolled over from previous year.
c) Amount of administrative funds retained by the social agency.
d) Number of weatherization jobs completed and total cost (excluding administrative costs).
e) Number of weatherization jobs "in progress" at the end of the calendar year.
f) Number, type, and total cost of baseload measures (non-heating) installed.

Per Empire's Sixth Revised Tariff Sheet 8c, they are required to allocate the funds in accordance with an established formula. The formula, calculated by the Division of Energy, allocates the dollars between the weatherization agencies based on the total Empire accounts enrolled with a weatherization agency and the percentage of households in poverty within the agency's service region. This funding is used to help with repairs needed to allow the home to meet the eligibility criteria so the LIWAP funding can be used to weatherize the home.

Staff supports the supplemental funding of the LIWAP because programs of this nature have a positive impact on the ability of low-income customers to pay their energy bills, which in turn reduces a utility company's amount of arrearages. Additionally, Staff recognizes that the LIWAP can also improve the safety and comfort level of a home while reducing energy usage. The LIWAP works with Community Action Agencies to assist customers through conservation, education and weatherization to reduce their use of energy; thus reducing the level of bad debts experienced by Empire. Therefore, Staff recognizes that LIWAP programs promote public policies beyond a demand-side resource program. Most electric and natural gas regulated utilities provide supplemental funding for low-income weatherization. Four utilities in

Missouri[78] provide funds to the Environmental Improvement and Energy Resources Authority ("EIERA") which are administered to the Weatherization Agencies similar to the USDOE funds.

Empire's last evaluation of the Low-Income Weatherization program was completed in 2009. There have been funding level changes to the program since 2009. Through the American Recovery and Reinvestment Act ("ARRA"), special federal funding of $128 million was provided for the DED-DE Weatherization Program for the period of April 2009 – March 2013 ("ARRA Period"). The ARRA provided an average of $6,500 of weatherization for households with income at 200% or less of the Federal Poverty Guidelines ("FPG"). In the three-year period (2006-2008) prior to the ARRA Period, federal funding for the DED-DE Weatherization Program was approximately $18 million and the average amount of weatherization per household was $3,000.

Due to these changes, Staff recommends that Empire perform another evaluation of the Low-Income Weatherization Assistance program. In order to get a better picture of the full impact of weatherization on low-income homes, Staff recommends that the evaluation include a representative sample of homes that use both electricity and natural gas for space conditioning. This sample should include homes served by Missouri Gas Energy ("MGE") a division of Laclede Corporation, provided that Empire can obtain the information necessary to determine cost effectiveness from MGE. In order to facilitate the evaluation process, Staff recommends that Empire invite MGE to one or more of the DSMAG meetings to discuss the evaluation and the potential of providing the evaluator with a customer's natural gas information.

Staff Expert/Witness: Kory Boustead

8. Current and Deferred Income Tax

a. Current Income Taxes

Current income tax for this case has been calculated by Staff largely consistent with the methodology used in Empire's most recent rate case, Case No. ER-2014-0351. Adjustments are made to net income to compute the current income tax expense. These adjustments are effectuated by taking adjusted net income and either adding to or subtracting from the net income various timing differences to obtain net taxable income for ratemaking purposes.

[78] Laclede Natural Gas, Ameren Missouri (electric and natural gas) and Liberty Utilities

(The term "timing differences" refers to the differences in time when certain costs can be deducted for purposes of determining financial statement net income and taxable income, respectively.) The adjustments are the result of various financial statement ("book") and tax timing differences as well as their implementation under separate tax ratemaking methods: flow-through versus normalization. The resulting net taxable income for ratemaking is then multiplied by the appropriate federal and state tax rates to obtain the current provision for income taxes. Staff used the current federal tax rate of 35 percent and the current state income tax rate of 6.25 percent in calculating Empire's income tax liability. The composite tax rate, taking into account both federal and state income tax rates, is 38.39%. The difference between the calculated current income tax provision and the per book income tax provision is the current income tax provision adjustment.

The tax timing differences used in calculating taxable income for computing current income tax are as follows:

Add Back to Operating Income Before Taxes:

- Book Depreciation Expense
- Non-Deductible Expense – Non-deductible meals and dues
- Contributions In Aid of Construction
- Book Amortization

Subtractions from Operating Income:

- Interest Expense – Weighted Cost of Debt X Rate Base
- Tax Depreciation – Straight-Line
- Tax Depreciation – Excess

** ____

__________ ** Thus Staff has made a deduction to net income before taxes to zero out current income tax expense and transfer the amount to deferred income tax expense.

Staff Expert/Witness: Amanda C. McMellen

b. Deferred Income Taxes

When a tax timing difference is reflected for ratemaking purposes in the deferred tax adjustment consistent with the timing used in determining taxable income for the calculation of current income tax payable to the IRS, the timing difference is given a "flow-through" treatment.

NP

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

For most utilities, it is necessary to break out a utility's tax depreciation into two separate components: tax straight-line depreciation and excess tax depreciation. Tax straight-line depreciation is different from book straight-line depreciation due to the different tax basis of property allowed under the tax code. Excess tax depreciation differs from straight-line book depreciation due to the higher depreciation rates allowed in the early years of an asset's life under the current tax code as compared to "straight-line" book depreciation rates. To calculate excess tax depreciation, Staff used the total tax depreciation amount included in the Company's filing in this case. Most tax basis differences were eliminated for assets placed into service after 1986 due to the Tax Reform Act ("TRA") enacted that year.

Staff's deferred income tax adjustment in this rate case consists of three components:

> 1. Depreciation tax timing difference: the difference between tax straight-line depreciation expense and tax depreciation expense. Staff has normalized this difference consistent with the treatment of this item in past Empire rate proceedings.
>
> 2. Other IRS timing differences: contributions in aid of construction. This amount is normalized consistent with Staff's calculation in the prior rate case filing.
>
> 3. Excess deferred income taxes resulting from the 1986 Tax Reform Act ("TRA"): Enactment of the TRA, which reduced the corporate income tax rates applicable to utilities, created excess deferred tax amounts associated with prior depreciation timing differences. As such, Staff uses an amortization to return excess deferred taxes resulting from the change in tax rates back to Empire's customers.

Staff Expert/Witness: Amanda C. McMellen

9. Insurance Expense

Insurance expense is the cost of protection obtained from third parties by utilities against the risk of financial loss associated with unanticipated events or occurrences. Utilities, like non-regulated entities, routinely incur insurance expense in order to minimize their liability (and, potentially, that of their customers) associated with unanticipated losses. Staff made an adjustment to annualize Empire's insurance expense to reflect the premiums paid as of September 30, 2015, the end of the update period.

Staff Expert/Witness: Jennifer K. Grisham

10. Bad Debt Expense

Bad debt, or uncollectible expense, is the portion of retail revenue that Empire is unable to collect from retail customers due to non-payment of bills. After a certain amount of time has passed, Empire's delinquent customer accounts are written off and turned over for collection. Empire and its collection agencies have been successful in collecting some portion of the delinquent amounts owed from customers even after they are written-off.

Staff examined the most recent five-year (October 2010 – September 2015) history of Empire's bad debt write-offs that were never collected (i.e., write-offs net of amounts subsequently collected). It is apparent from a review of this data that Empire's bad debt expense fluctuates from one year to the next. Therefore, Staff calculated a five-year average of the uncollectable percentage of bad debt to revenue, which was then applied to Staff's annualized and adjusted level of test year retail rate revenues to obtain the normalized level of bad debt expense.

Staff Expert/Witness: Ashley R. Sarver

11. Postage

Staff adjusted postage expense to reflect the annualized amount of postage through the end of the update period, September 30, 2015.

Staff Expert/Witness: Jennifer K. Grisham

12. PSC Assessment and Rate Case Expense

a. PSC Assessment

The adjustment represents the difference between the Staff's annualized PSC Assessment and the amount included in the starting point in this case. The most recent PSC Assessment, in effect for the fiscal year July 1, 2015, to June 30, 2016, was used in the Staff's annualization.

Staff Expert/Witness: Jennifer K. Grisham

b. Rate Case Expense

i. Normalization

Staff reviewed Empire's rate case expense related to this case for the reasonableness and prudence of all services secured and all costs incurred. Staff included the actual costs incurred by Empire for rate case expense as of February 29, 2016, directly related to this case (No. ER-2016-0023). Staff's rate case expense adjustment is based upon all costs associated with filing and bringing this case before the Commission such as consulting fees, employee travel expenditures, and legal representation. Staff has normalized the rate case expense over a three (3) year period. The ultimate amount of rate case expense incurred by the Company in this proceeding will be directly associated with the length of the case through the settlement conference and hearing process.

The Company's depreciation study, which was submitted as part of this rate case, fulfills the requirement to perform a study every five (5) years. Therefore, this cost is being normalized over a five-year period.

The Company also performed a line loss study as a part of this rate case. According to the Missouri Code of State Regulations (CSR) 4 CSR 240-20.090(9), the electric utility shall conduct a Missouri jurisdictional loss study no less often than every four (4) years thereafter, on a schedule that permits the study to be used in the general rate proceeding necessary for the electric utility to continue to utilize rate adjustment mechanism. Staff is normalizing this cost over a four-year period.

Rate case expense will also be examined in the true-up portion of this case. Accordingly, Staff will continue to examine the actual costs incurred by Empire relating to the processing of the rate case and include all prudently incurred expenses in the cost of service analysis.

Staff Expert/Witness: Ashley R. Sarver

ii. Sharing Recommendation

In the *Staff Investigative Report on Rate Case Expense* ("Report") filed in Case No. AW-2011-0330 in September 2013, Staff made certain recommendations regarding ongoing rate recovery policies for utility rate case expense. Within the Report, Staff asserted that rate case expense provides a benefit to both utilities and customers. Staff noted that a practice of granting utilities full recovery of incurred rate case expense does not provide the utility with strong incentives to reasonably limit their expenditures in this area. Staff also expressed concerns in the Report that full rate recovery of incurred rate case expense gives a utility an inappropriate financial advantage over other parties and interveners in rate case which must operate with budgetary and other financial restrictions. It was Staff's conclusion in the Report that the application of "structural incentives" to rate case expense recovery be considered by the Commission in order to acknowledge the duel-beneficiary nature of rate case expense incurrence, alleviate a utility's advantage over other parties in a rate case, and to incentivize a utility to file a "tight" case that is easier to process.

One option mentioned by Staff in the Report to accomplish the above-stated goals was for rate case expense to be shared between ratepayers and shareholders according to the percentage of a utility's rate increase request that is ultimately determined to be just and reasonable by the Commission. This is the mechanism that Staff recommends be employed in this rate case to normalize rate case expense. This sharing mechanism assigns to ratepayers costs that are reasonable and from which ratepayers receive a benefit, and only those costs; it reduces the Company's significant financial advantage over other participants in the rate case process; and it provides an incentive for the Company to control its costs.

The Commission recently provided specific guidance on this issue in its *Report and Order* in **Re: Kansas City Power & Light,** Case No. ER-2014-0370, which referenced the aforementioned Staff Report. In its decision, on page 72 of Order, the Commission stated the following:

> The Commission finds that in order to set just and reasonable rates under the facts in this case, the Commission will require KCPL shareholders to cover a portion of KCPL's rate case expense. One method to encourage KCPL to limit its rate case expenditures would be to link KCPL's percentage of recovery of rate case expense to the percentage of its rate case request the Commission finds just and reasonable.[[79]] The Commission determines that this approach would directly link KCPL's recovery of rate case expense to both the reasonableness of its issue positions and the dollar value sought from customers in the this rate case.[[80]]
>
> The Commission concludes that KCPL should receive rate recovery of its rate case expense in proportion to the amount of revenue requirement it is granted as a result of this Report and Order, compared to the amount of its revenue requirement rate increase originally requested.

After reviewing the evidence and circumstances of Empire's current ER-2016-0023 rate case, Staff recommends that rate case expense be shared between Empire ratepayers and shareholders by the same method suggested in the Staff Report issued in Case No. AW-2011-0330, and ordered by the Commission in the recent KCPL rate case, Case No. ER-2014-0370. Staff recommends the percentage of rate case expense which is to be borne by the ratepayers be equal to the percentage of its rate increase request that is determined to be just and reasonable. Ultimately, this will be the percentage of the Company's rate increase request that is granted by the Commission. For its direct filing, Staff calculated a percentage based on Staff's current revenue requirement recommendation compared to the amount Empire requested in this case. Then, that percentage was applied to the actual rate case expenses incurred to date and normalized over three (3) years. This calculation will be updated throughout the case. Staff recommends that the depreciation study and line loss study be exempt from the application of the recommended sharing percentage and the recoverable over the years stated above.

Staff Expert/Witness: Amanda C. McMellen

[79] This method can be expressed as: (Revenue Requirement Approved / Original Revenue Requirement Requested) X 100 = allowable percentage of rate case expense.

[80] It is understood that some of the issues litigated in this case do not directly affect the overall revenue requirement granted by the Commission; but it is clear that the vast majority of the litigated issues do have a direct or indirect impact on the revenue requirement. Accordingly, percentage sharing is a reasonable approach to correlating recovery of rate case expense to the relationship between the amount of litigation that benefited both ratepayers and shareholders and that which benefited only shareholders.

13. Injuries and Damages and Workers' Compensation

Empire maintains workers' compensation insurance for the benefit of its employees. The workers' compensation adjustment proposed by Staff annualizes this expense based upon the premiums in effect at September 2015 to reflect an ongoing and normal expense level for Empire.

From time to time, Empire is sued by claimants seeking payment of damages. If Empire loses the lawsuit, it is likely to be required to make a payout to the aggrieved party. Alternatively, it may choose to enter into an out-of-court settlement, also resulting in a payout. Based upon generally accepted accounting principles, Empire is required to charge to current expense an estimate of its future payouts for injuries and damages claims. To determine a normalized level of this expense, Staff used a five-year average of actual injuries and damages and workers' compensation payments in its cost of service report, instead of relying upon accounting estimates. Staff applied an allocation of 49.62 percent to the five-year average of actual payments made for injuries and damages. The allocation of 49.62 percent represents the electric expense portion of the payments. The remaining amounts of the payments (50.38%) are allocated to the Company's construction, water operations and below-the-line activities. A five-year average of actual payments was used to normalize this expense because Staff's analysis shows a considerable fluctuation in the annual amount of payments from one year to the next.

Staff Expert/Witness: Ashley R. Sarver

14. Advertising Expense

Empire engaged in various advertising activities during the test year. In making its recommendation of the allowable level of Empire's advertising expense, Staff relied on the principles that the Commission determined were appropriate in the KCPL rate case, Case No. EO-85-185, *et al.*[81] Under these principles, the Commission recognizes five categories of advertisements, and specifies rate treatment based on each of the following categories:

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

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[81] ***Re: Kansas City Power and Light Company***, 28 Mo. P.S.C. (N.S.) 228, 269-71 (1986).

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 applies this rationale by stating that a utility's revenue requirement should: 1) always include the reasonable and necessary cost of general and safety advertisements; 2) never include the cost of institutional or political advertisements; and 3) include the cost of promotional advertisements only to the extent that the utility can provide cost-justification for the advertisement.

Following this guidance, Staff's starting point in this case includes adjustments excluding promotional and institutional advertising expenses from recovery in rates in the amount of $155,394. No further adjustments were necessary for this case.

Staff Expert/Witness: Amanda C. McMellen

15. Outside Services

Various outside (independent) contractors and vendors provide legal, auditing, and other services to Empire to carry out its operational activities as needed. Staff reviewed Empire's outside services expense booked to Accounts 923.045 and 923.047 for the test year through the update period ending September 30, 2015. Staff normalized the amounts of outside services on a going forward basis by calculating a five-year average of incurred costs for these accounts in the amount of $2,448,464. This adjustment does not include outside services related to rate case expense. Outside services incurred for rate case purposes are booked in a separate account.

Staff Expert/Witness: Keith D. Foster

16. Dues and Donations

Staff reviewed the list of membership dues paid and donations made to various organizations that Empire charged to its utility accounts during the test year. For the starting point in this case, Staff recommends adjustments to exclude various dues and donations that were included by Empire in its above-the-line expense accounts. In ***Re: Missouri Public Service, a Division of UtiliCorp United, Inc.***, Case Nos. ER-97-394, *et al., Report and Order,* 7 Mo.P.S.C.3d 178, 212 (1998), the Commission stated:

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

Staff excluded dues and donations that do not have any direct benefit to ratepayers and were not necessary for the provision of safe and adequate service. Allowing Empire to recover these expenses through rates causes the ratepayer to involuntarily contribute to these organizations. Examples of dues excluded from recovery in the rate case, based on the Commission's *Report and Order* mentioned above, are dues paid to the Home Builders Association, Rotary Club, and Twin Hills Golf and Country Club. An example of a donation that was excluded is donated merchandise purchased from Wal-Mart Inc. Area Chamber of Commerce dues were allowed, but National and State Chamber of Commerce dues were disallowed as being duplicative costs to the local Chamber of Commerce organizations. No further adjustments are necessary for this case.

Staff Expert/Witness: Amanda C. McMellen

17. Edison Electric Institute ("EEI") Dues

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

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

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

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

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

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

Empire failed to quantify ratepayer and shareholder benefits from its participation in EEI; therefore, the Staff removed total EEI dues included in the test year of $147,299 from Empire's cost of service for the starting point in this case. No further adjustment is necessary for this case.

Staff Expert/Witness: Amanda C. McMellen

18. Tree Trimming Expense/Infrastructure Inspection Expense

In Case No. ER-2008-0093, the Commission authorized Empire to set up a two-way tracker mechanism to account for any difference between Empire's incurred vegetation management (i.e., tree trimming) and infrastructure inspection costs compared to an estimated target annual amount of $8,575,000. While Staff and the Company agreed to continue the vegetation tracker beyond the 2008 rate case, the infrastructure tracker was eliminated on May 12, 2010, as per the *Non-Unanimous Stipulation and Agreement*, File No. ER-2010-0130. In the last rate case, File No. ER-2014-0351, Staff and the Company agreed to discontinue the vegetation tracker effective July 31, 2015, as stated in the *Non-Unanimous Stipulation and Agreement* filed in that proceeding. Additionally, in the last case, Staff accepted Empire's recommendation to reduce the ongoing amount of tree trimming expense from $12 million dollars to $11 million dollars. In this current case, Staff updated the vegetation management tracker balance as of July 31, 2015, and will perform a true-up for the unamortized balance (*see* Section VIII. K.).

Staff adjusted the infrastructure inspection remediation cost incurred in this case. These remediation costs resulted from the Company performing preventive maintenance on its transmission and distribution system during the inspection cycles mandated under the infrastructure inspection rule. Staff reviewed the remediation costs incurred over the last five years ending December 31, 2014, and annualized the costs to increase the test year expense level in the amount of $127,211.

Staff Expert/Witness: Jermaine Green

19. SWPA Amortization

As described previously in this Report, in Case No. ER-2011-0004, Empire agreed to flow the SWPA payment back to its customers over a ten-year period via a tracker mechanism. This yearly amortization, unlike other amortizations discussed in this Report, does not increase the Company's expense levels but is a reduction or offset to expenses. The starting point in this case reflects an appropriate amount of annual amortization expense. No further adjustments are necessary for this case.

Staff Expert/Witness: Amanda C. McMellen

20. Lease Expense

Lease costs are those costs incurred by Empire for the leasing of its equipment and building space. Staff submitted Data Request No. 0061 to Empire asking for a list of all lease agreements (office, vehicle, computers, etc.) charged to Missouri electric operations, along with the lease costs and information concerning all changes to the lease amounts since the since the last rate case, No. ER-2014-0351. Staff examined these costs for the test year, updated through September 30, 2015, and did not make an adjustment because there were no material differences since the last rate case.

Staff Expert/Witness: Ashley R. Sarver

21. Solar Rebates

On May 5, 2015, Empire issued tariffs to establish solar rebate payments procedures, and to revise its net metering tariffs to accommodate the payment of solar rebates.[82] The tariff submitted under YE-2015-0322 became effective on May 16, 2015. Based upon staff's review of the costs recorded to date in Account 182377, Staff has amortized the costs over a ten-year period. Staff is using the September 30, 2015, balance of this regulatory asset in rate base in this case. The Staff has also included an adjustment in the Income Statement to amortize these costs to expense. Staff will make further adjustments in the true-up audit in order to address any additional solar rebate spending through that point in time.

Staff Expert/Witness: Ashley R. Sarver

22. Tornado AAO Amortization

The Commission issued an order on November 30, 2011, that approved and incorporated the *Stipulation and Agreement* in Empire's *Application for an Accounting Authority Order*, Case No. EU-2011-0387. In that *Stipulation and Agreement*, the parties agreed to allow Empire to defer to Account 182.3 the following items: Other Regulatory Assets, incremental operations and maintenance expenses associated with the repair, restoration and rebuild activities associated with the May 22, 2011, tornado; and depreciation and carrying charges equal to its ongoing Allowance for Funds Used During Construction rates associated with tornado-related capital expenses. The Company agreed that if it filed a general rate case in Missouri by June 1, 2013, then Empire would begin to amortize over a ten-year period the deferral balance beginning at the earlier of: 1) the effective date of new rates implemented in its next general rate increase case or rate complaint case; or 2) June 1, 2013. As of September 30, 2015, Empire had a deferred balance of $3,018,860 in Account 182.3 for tornado-related expenses. Staff has not included this balance in rate base because of the Commission's long-standing policy of "sharing" the financial impact of extraordinary events, such as tornado expenses, through exclusion of the unamortized portion of an accounting authority order deferral from rate base the annual amortization calculated in last rate case, ER-2014-0351, has not changed. Therefore, Staff included the same annualized amount in this case.

Staff Expert/Witness: Amanda C. McMellen

[82] Order Approving Expedited Tariff, MoPSC File No. ET-2015-0285, page 1.

23. Software Maintenance Expense

Empire has contracts, operating licenses, and agreements with vendors that provide maintenance, upgrades to software, and support for its computer software. Based on the General Ledger for the period of September 1, 2014, through the update period ending September 30, 2015, the monthly rates for the majority of Empire's software maintenance agreements increased since the last rate case. However, while there were no entries for one software maintenance vendor, Power Costs Inc. ("PCI"). Staff annualized the expense for each of the suppliers based on the current rate for each as recorded on the General Ledger at September 30, 2015, setting the PCI annualized amount to zero, resulting in an overall decrease in annualized software maintenance expense. Therefore, Staff made an adjustment of $(169,589) in Account 921-Office Supplies and Account 923- Outside Services, to decrease the software maintenance expense to reflect the annualized amount of $873,581 as of September 30, 2015. The software items that are included in these maintenance expenses are Triple Point INSSINC – Futrack, Intergraph GMS and OMS, Maximo User License (through Total Resource Management), Oracle PeopleSoft, and Power Plant & Budgeting.

Staff Expert/Witness: Keith D. Foster

24. Corporate Expenses

Due to Staff concerns with the reliability of Empire's current approach of allocating its corporate costs to its electric, gas, water and non-regulated activities, certain adjustments have been proposed in this case. First, Empire is currently not allocating any Administrative and General ("A&G") expenses to their water operations. Staff has made an adjustment to remove a portion of A&G expenses currently charged to electric operations in order to allocate the costs to water operations. Staff has also made an adjustment to remove a portion of costs related to EDI due to concerns about the methodology the currently uses to allocate common costs to non-regulated activities, as described in Section IX. A., Corporate Allocations.

Staff Expert/Witness: Amanda C. McMellen

25. Capitalized Depreciation

Expenses related to construction projects are accumulated in construction-work-in-progress accounts, and are only eligible to be included in rates subsequent to the completion of the project. The capitalized expenses include depreciation expense associated with assets used in construction such as power operated equipment and transportation equipment. Capitalized depreciation expenses must be subtracted from the total depreciation expense amount calculated by using Empire's total plant-in-service balances in order to prevent double recovery. Therefore, Staff has deducted capitalized depreciation from its total depreciation expense in order to arrive at the amount of depreciation expense associated with O&M related functions.

Staff Expert/Witness: Amanda C. McMellen

XI. Fuel Adjustment Clause ("FAC")

A. Policy

In summary, Staff makes the following recommendations regarding Empire's Fuel Adjustment Clause ("FAC") to the Commission:

1. Continue Empire's FAC with modifications;
2. Include a revised Base Factor[83] in the FAC tariff sheets calculated from the Base Energy Cost[84] that the Commission includes in the revenue requirement upon which it sets Empire's general rates in this case; and
3. Order Empire to continue to provide the additional information as part of its monthly reports[85] as Empire agreed to do in the *Revised Stipulation and Agreement* filed April 8, 2015, in Rate Case No. ER-2014-0351 and has continued to provide in its monthly reports.

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[83] Base Factor is defined in Empire's Original Tariff Sheet No. 17l as "BASE FACTOR ("BF"): The base factor is the base energy cost divided by net generation kWh determined by the Commission in the last general rate case.

[84] Base Energy Cost is defined in Empire's Original Revised Tariff Sheet No. 17l as "Base energy cost are ordered by the Commission in the last rate case consistent with the costs and revenues included in the calculation of the Fuel and Purchased Power Adjustment ("FPA") and include fuel costs incurred to support sales ("FC") plus purchased power costs ("PP") plus net emission costs ("E") minus off-system sales revenues ("OSSR") minus renewable energy credit revenue ("REC").

[85] Monthly reports are required by 4 CSR 240-3.161(5).

At this time Staff does not have its estimate for the Base Factor for the FAC, but will provide it and a discussion on the calculation of the Base Factor when Staff files its Class Cost of Service/Rate Design Report on April 6, 2016. Staff will use the Base Energy Cost and the kWh at the generator from its fuel run to develop the Base Factor.

B. History

Senate Bill 179[86] ("SB 179") was passed and enacted in 2005. It authorizes 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 grants the Commission the authority to approve, modify, or reject the electric utility's request. SB 179 also states 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 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, all of 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 all of the increased cost.

The Commission first authorized a FAC for Empire in its *Report and Order* in Empire's 2008 rate case, Case No. ER-2008-0093, and approved FAC tariff sheets in that case with an effective date of September 1, 2008. In general rate cases Case Nos. ER-2010-0130, ER-2011-0004, ER-2012-0345, and ER-2014-0351, the Commission authorized continuation, with modifications, of Empire's FAC. The primary features of Empire's present FAC (tariff sheet numbers 17l through 17t) include:

[86] Section 386.266, RSMo. 2010 Cum. Supp.

- Two 6-month accumulation periods: March through August and September through February;
- Two 6-month recovery periods: December through May and June through November;
- Fuel Adjustment Rate ("FAR") filings semi-annually not later than April 1 and October 1;
- One Base Factor for all calendar months of the year;
- A 95%/5% sharing mechanism;
- FAR rates for individual service classifications adjusted for the two Empire service voltage levels, rounded to the nearest $0.00001, and charged on each kWh billed; and
- True-up of any over- or under-recovery of revenues following each recovery period with a true-up amount being included in the determination of FAR for a subsequent recovery period.

Empire has made Fourteen FAR filings, File Nos.:

EO-2009-0349	ER-2010-0105	ER-2010-0275
ER-2011-0095	ER-2011-0320	ER-2012-0098
ER-2012-0326	ER-2013-0122	ER-2013-0442
ER-2014-0087	ER-2014-0264	ER-2015-0085
ER-2015-0247	ER-2016-0080	

The resulting changes to the Empire FARs ordered by the Commission are summarized in the **Continuation of FAC** section of this report. The Base Factor was originally set in Empire's 2008 general rate case and was changed as a result of the negotiated settlements in Empire's 2010, 2011, and 2012 general rate cases, and by Commission *Report and Order* in the 2014 general rate case.

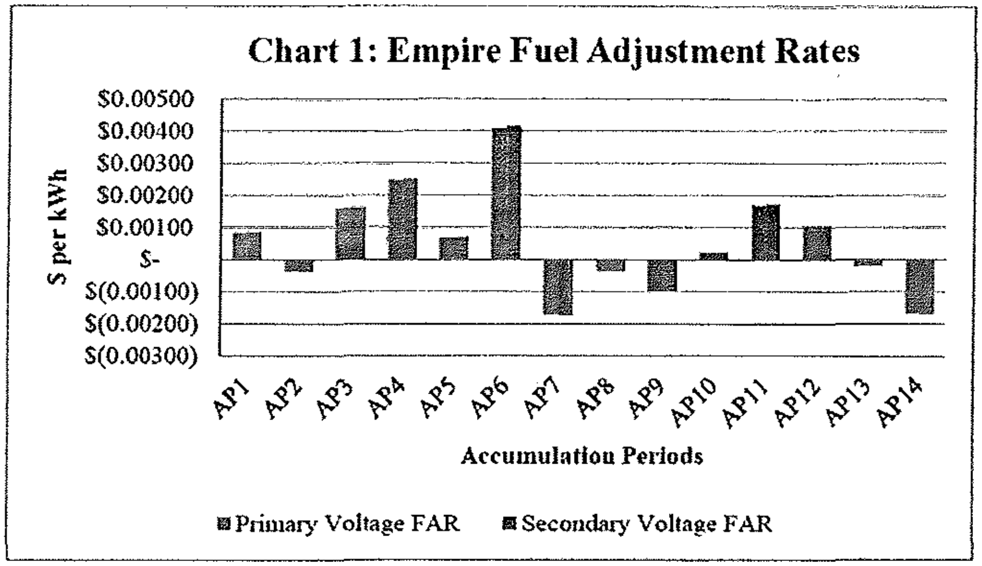
Staff has filed five prudence review reports[87] (File Nos. EO-2010-0084, EO-2011-0285, EO-2013-0114, EO-2014-0057, and EO-2015-0214) concerning its review of the costs and revenues of the Company's FAC and found no evidence of imprudent decisions by the Company's management related to fuel, purchased power and net emission costs, off-system sales revenues and renewable energy credits revenues for the time periods reviewed.

[87] 4 CSR 240-20.090(7) Prudence Reviews Respecting RAMs [rate adjustment mechanisms]. A prudence review of the costs subject to the RAM shall be conducted no less frequently than at eighteen (18)-month intervals.

C. Continuation of FAC

Staff recommends that the Commission approve, with modifications, the continuation of Empire's FAC.

The Company has filed for and received approval of changes to its fuel adjustment rates ("FARs") for fourteen (14) completed accumulation periods ("AP") (AP1 through AP14). The primary and secondary voltage FARs for each accumulation period are reflected in Chart 1.



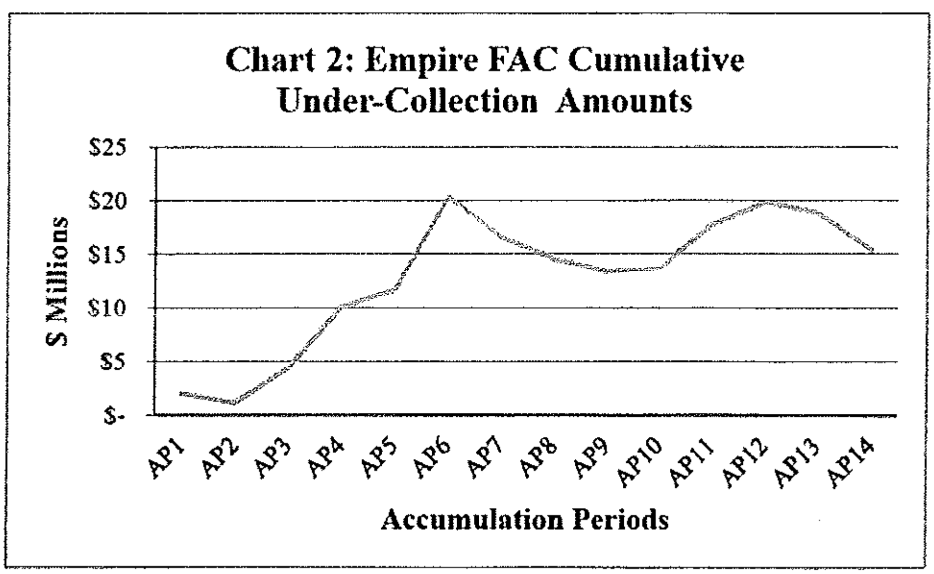
The time periods of the accumulation periods ("APs") are as follows:

AP1 Sep 08 – Feb 09	AP2 Mar 09 – Aug 09
AP3 Sep 09 – Feb 10	AP4 Mar 10 – Aug 10
AP5 Sep 10 – Feb 11	AP6 Mar 11 – Aug 11
AP7 Sep 11 – Feb 12	AP8 Mar 12 – Aug 12
AP9 Sep 12 – Feb 13	AP10 Mar 13 – Aug 13
AP11 Sep 13 – Feb 14	AP12 Mar 14 – Aug 14
AP13 Sep 14 – Feb 15	AP14 Mar 14 – Aug 15

The Company's actual Total Energy Cost have exceeded the then-effective Base Factors multiplied by monthly usage billed to Empire's customers' in eight out of fourteen completed accumulation periods. Actual Total Energy Cost include: Empire's total booked costs as allocated to its Missouri retail jurisdiction for fuel consumed in the Company's generating units, including the costs associated with the Company's fuel hedging program; purchased power energy charges, including applicable transmission fees; Southwest Power Pool variable costs; air quality control system consumables, such as anhydrous ammonia, limestone, and powder activated carbon, and emission allowance costs. Actual Total Energy Cost does not include the purchased power demand costs, since these are considered to be fixed costs. Actual FAC costs are off-set by actual Revenue from Off-System Sales, actual Net Emission Costs, and actual Renewable Energy Credit Revenues. During six accumulation periods, AP2, AP7, AP8, and AP9, AP13, and AP14, Empire's Base Energy Cost exceeded actual Total Energy Cost; 95% of such excess amounts were returned to customers during six recovery periods ("RP") RP2, RP7, RP8, RP9, RP13 and RP14. In eight of its accumulation periods (AP1, AP3, AP4, AP5, AP6, AP10, AP11, and AP12), Empire under-collected its actual Total Energy Costs, and 95% of the amounts of under-collection were recovered from Empire's Missouri customers during recovery periods RP1, RP3, RP4, RP5, RP6, RP10, RP11, and RP12.

At the conclusions of its general electric rate cases, during AP3, AP6, AP10, and AP14 – Case Nos. ER-2010-0130, ER-2011-0004, ER-2012-0345, and ER-2015-0351 respectively – the Base Factors in Empire's FAC were re-set.

Charts 2 and 3 illustrate the following information for the first fourteen (14) accumulation periods: 1) cumulative under collection amount which is equal to Total Energy Cost ("TEC") less Net Base Energy Cost ("B") for Empire's Missouri jurisdiction,[88] and 2) percentage of cumulative under-collection amount which is equal to 100*(TEC-B)/TEC.



[88] For AP14, this is the amount on line 5 of Empire's 1st Revised Sheet No. 17t.

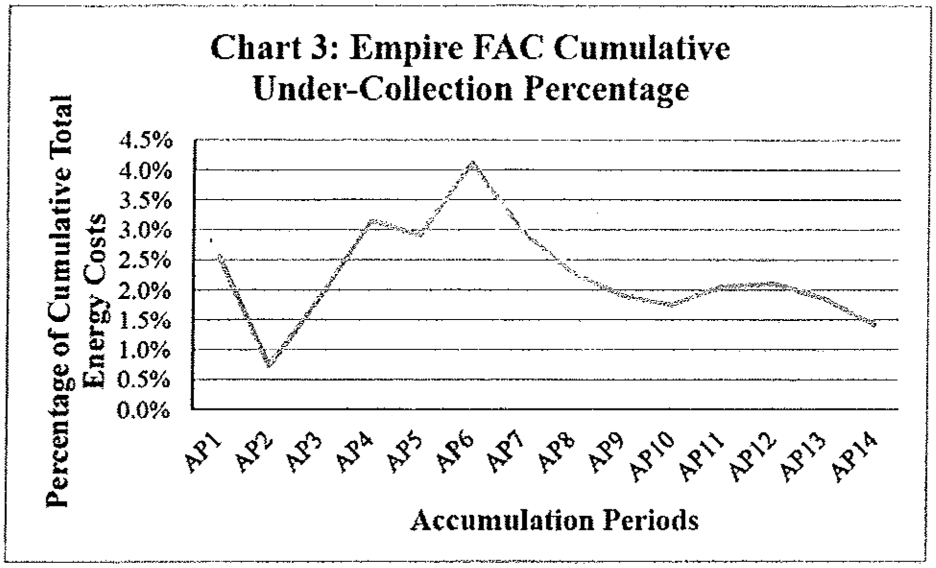


Chart 1 illustrates the variability of the FARs as a result of variations in each accumulation period's billed Base Energy Cost and actual Total Energy Cost. From Charts 2 and 3, Staff observes that the FAC cumulative under-collected amount over eight years is approximately $15 million or about 1.4 percent of total actual Total Energy Cost of $1,085 million during AP1 through AP14.

Staff recommends continuation of Empire's FAC with modifications. As shown in the previous charts and discussion, Empire's actual Total Energy Costs continue to be relatively large,[89] volatile, and beyond the control of the Company. In addition, the Southwest Power Pool ("SPP") conversion to the Integrated Marketplace ("IM") on March 1, 2014, represents a fundamental change in how Empire's generation is dispatched and how Empire serves its native load. By having an FAC that includes IM costs, the effects of the IM will flow through the FAC to both the Company and its customers in a timely manner.

D. Southwest Power Pool Integrated Market

On February 1, 2007, SPP started the Energy Imbalance Services ("EIS") Market when it began dispatching wholesale electricity. The wholesale energy market is intended to allow for more efficient deployment of generation across the SPP region through the establishment of an

[89] Empire's proposed Base Energy Cost for this case represents 37% of the requested total revenue requirement.

offer-based market for energy imbalance services. The EIS Market was decommissioned March 11, 2014, following the start of the IM 10 days earlier, on March 1, 2014. The IM is a market expansion which added a market functionality that coordinates next-day generation across the region with the goals of maximizing cost-effectiveness, providing participants with greater access to reserve energy, improving regional balancing of electricity supply and demand, and facilitating the integration of renewable resources. Specifically, the Integrated Marketplace includes:

- A day-ahead market with transmission congestion rights ("TCRs");
- A reliability unit commitment process;
- A real-time balancing market replacing SPP's EIS market;
- Incorporation of a price-based operating reserve market;
- Combining current balancing authorities into a single SPP balancing authority.

Empire is registered in the SPP IM as both a generating and load-serving entity. In the previous rate case, Case No. ER-2014-0351, Empire's FAC tariff and the calculation of the FAC Base Factor were changed to reflect Empire's participation in the SPP IM. Empire's currently-approved FAC went into effect on July 26, 2015, and is structured to conform to the IM market. AP14 is the most recently completed accumulation period. One month of AP14, August 2015, was covered by the currently-approved FAC.

E. Revising the Base Factor

Correctly setting the Base Factor in Empire's FAC tariff sheets is critical to both a well-functioning FAC and a well-functioning FAC sharing mechanism. For the reasons below, Staff recommends the Commission require the Base Factor in Empire's FAC be set based on the Base Energy Cost that the Commission includes in the revenue requirement which it sets Empire's general rates in this case.

Table 1 below shows three scenarios in which the FAC Base Energy Cost used to set the FAC Base Factor are equal to, less than, or greater than the Base Energy Cost in the revenue requirement upon which the Commission sets general rates:

Table 1: Base Energy Cost Case Studies				
		Case 1	Case 2	Case 3
Line	**95%/5% Sharing Mechanism**	Energy Cost in FAC **Equal To** Base Energy Cost in Rev. Req.	Energy Cost in FAC **Less Than** Base Energy Cost in Rev. Req.	Energy Cost in FAC **Greater Than** Base Energy Cost in
a	Revenue Requirement	$ 10,000,000	$ 10,000,000	$ 10,000,000
b	Base Energy Cost in Rev. Req.	$ 4,000,000	$ 4,000,000	$ 4,000,000
c	Base Energy Cost in FAC	$ 4,000,000	$ 3,900,000	$ 4,100,000
	Outcome 1: Actual Energy Cost **Greater Than** Base Energy Cost in Revenue Requirement			
d	Actual Total Energy Cost	$ 4,200,000	$ 4,200,000	$ 4,200,000
	Billed to Customer:			
= b	in Permanent Rates	$ 4,000,000	$ 4,000,000	$ 4,000,000
e = (d - c) x 0.95	through FAC	$ 190,000	$ 285,000	$ 95,000
f = b + e	Total Billed to Customers	$ 4,190,000	$ 4,285,000	$ 4,095,000
g = f - d	**Kept/(Paid) by Company**	**$ (10,000)**	**$ 85,000**	**$ (105,000)**
	Outcome 2: Actual Energy Cost **Less Than** Base Energy Cost in Revenue Requirement			
h	Actual Energy Cost	$ 3,800,000	$ 3,800,000	$ 3,800,000
	Billed to Customer:			
= b	in Permanent Rates	$ 4,000,000	$ 4,000,000	$ 4,000,000
i = (h - c) x 0.95	through FAC	$ (190,000)	$ (95,000)	$ (285,000)
j = b + i	Total Billed to Customers	$ 3,810,000	$ 3,905,000	$ 3,715,000
k = j - h	**Kept/(Paid) by Company**	**$ 10,000**	**$ 105,000**	**$ (85,000)**

Case 1 illustrates that if the FAC Base Energy Cost used for the Base Factor is equal to the Base Energy Cost in the revenue requirement used for setting general rates, the utility does not over or under-collect as a result of the level of total actual energy costs. The FAC works as it is intended to.

Case 2 illustrates that if the FAC Base Energy Cost used for the Base Factor is less than the Base Energy Cost in the revenue requirement used for setting general rates, the utility will collect more than was intended and customers pay more than the FAC was designed for them to pay, regardless of the level of actual energy costs.

Case 3 illustrates that if the FAC Base Energy Cost used for the Base Factor is greater than the Base Energy Cost in the revenue requirement used for setting general rates, the utility will not collect all of the costs that was intended in the FAC design, and customers pay less than the entire amount intended regardless of the level of actual energy costs.

These three cases illustrate the importance of setting the Base Factor in the FAC correctly; *i.e.*, revising the Base Factor to match the Base Energy Cost in the revenue requirement used for setting general rates. Case 1 is the preferred case, and illustrates how the FAC is intended to work.

F. Additional Reporting Requirements

Due to the accelerated Staff review process necessary with FAC adjustment filings[90] Staff recommends the Commission order Empire to continue to provide the following information as part of its monthly reports as Empire agreed to do in the *Revised Stipulation and Agreement* filed April 8, 2015, in Rate Case No. ER-2014-0351, and has continued to provide in its monthly reports;

1. Monthly Southwest Power Pool ("SPP") market settlements and revenue neutrality uplift charges;
2. Notify Staff within 30 days of entering a new long-term contract for transportation, coal, natural gas or other fuel; natural gas spot transactions are specifically excluded;
3. Provide Staff with a monthly natural gas fuel report that includes all transactions, spot and longer term; the report will include term, volumes, price and analysis of number of bids;
4. Notify Staff within 30 days of any material change in Empire's fuel hedging policy, and provide the Staff with access to new written policy;
5. Provide Staff its Missouri Fuel Adjustment Interest calculation workpapers in electronic format with all formulas intact when Empire files for a change in the cost adjustment factor;
6. Notify Staff within 30 days of any change in Empire's internal policies for participating in the SPP;

[90] The company must file its FAC adjustment 60 days prior to the effective date of its proposed tariff sheet. Staff has 30 days to review the filing and make a recommendation to the Commission. The Commission then has 30 days to approve or deny Staff's recommendation.

7. Continue to provide Staff access to all contracts and policies upon Staff's request, at Empire's corporate office in Joplin, Missouri.

Staff Expert/Witness: David C. Roos

G. FAC Voltage Adjustment Factors

Rule 4 CSR 240-20.090(9) requires an electric utility that desires to continue using a Commission authorized Rate Adjustment Mechanism ("RAM"), such as the current request of Empire in regard to its FAC, to complete a jurisdictional system loss study of the corresponding energy losses experienced in its delivery of electricity. This study must be based upon a consecutive twelve-month period, preferably a calendar year, and be conducted at least every four years following the Commission's initial approval of its FAC.[91] Empire provided a loss study in its follow-up response to Staff Data Request No. 100 in this case on January 7, 2016. This loss study contains system loss calculations/determinations based on data collected during calendar year 2014. Staff used the information in this loss study in developing the following primary and secondary voltage level adjustment factors:

Voltage Level	Voltage Adjustment Factor
Primary	1.0464
Secondary	1.0657

These voltage adjustment factors account for the energy losses experienced in the delivery of electricity from the generator to the customer. These factors will be utilized in Staff's determination of a Fuel Adjustment Rate ("FAR"), applicable to the individual voltage service classification of a particular customer in the corresponding FAC tariff.

Staff Expert/Witness: Alan J. Bax

[91] 4 CSR 240-20.090(9) Rate Design of the RAM. The design of the RAM rates shall reflect differences in losses incurred in the delivery of electricity at different voltage levels for the electric utility's different rate classes. Therefore, the electric utility shall conduct a Missouri jurisdictional system loss study within twenty-four (24) months prior to the general rate proceeding in which it requests its initial RAM. The electric utility shall conduct a Missouri jurisdictional loss study no less often than every four (4) years thereafter, on a schedule that permits the study to be used in the general rate proceeding necessary for the electric utility to continue to utilize a RAM.

H. Loss Study – Compliance with FAC Rules

Empire supplied Staff with a loss study in Response to Staff Data Request 100. The loss study analyzed data compiled during calendar year 2014. Therefore, Empire remains in compliance with the rule requiring a current loss study when requesting the initiation or the continuance of a FAC per 4 CSR 240-20.090(9).

Staff Expert/Witness: Alan J. Bax

I. Heat Rate Testing Review

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

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

The Commission authorized Empire's FAC in Case No. ER-2008-0093. The FAC was continued in Case Nos. ER-2010-0130, ER-2011-0004, ER-2012-0345, and ER-2014-0351. Empire has requested the FAC be continued in the current general rate proceeding, Case No. ER-2016-0023.

Empire witness Todd W. Tarter filed the results of the most recent heat rate/efficiency tests for Empire's generating units in schedule TWT-7 of his direct testimony. Staff has conducted a review of those results and found them to be reasonable based on comparisons with data filed in previous general rate case proceedings and known changes in power plant operating parameters. All of the testing dates submitted by Empire were found to be in accordance with the twenty-four (24) month requirement of 4 CSR 240-3.161(3)(Q).

Staff Expert/Witness: Charles T. Poston

XII. Miscellaneous

A. Proposed Acquisition

On December 13, 2015, Empire issued a press release, in response to media reports concerning stock trading activity, confirming that the Company "is in the early stages of exploring strategic alternatives, and has retained a financial advisor with regard to the exploration of such strategic alternatives. No decision regarding the strategic alternatives has been made by the Board of Directors." No other information was provided at that time. On February 9, 2016, Empire announced that Algonquin Power & Utilities Corp. ("Algonquin") will acquire The Empire District Electric Company and included details related to this activity. Algonquin is a company based in Oakville, Ontario, which has a U.S. subsidiary, Liberty Utilities, which is currently regulated by the PSC. A subsidiary of Liberty Utilities, Liberty Utilities (Central) Co., was created to acquire the capital stock of Empire for this proposed transaction and is an indirect subsidiary of Algonquin. On February 25, 2016, Empire filed a notice with the PSC concerning this proposed transaction.

In response to the announcement of this proposed transaction, Staff issued Data Request No. 0201 in this case requesting the hours spent by Empire employees related to this proposed transaction. Empire's response was that any time spent on this proposed acquisition by Empire employees has not been separately tracked. Staff is concerned that these hours were not tracked and asserts it is unreasonable that Empire did not measure its cost related to its holding company function. Empire's failure to measure these costs resulted in acquisition payroll and related expense being recorded as utility expense. Staff will conduct a review to determine the level of this activity that occurred before September 30, 2015. This is a matter that will definitely impact the update period through March 31, 2016. It is unclear at this time whether any of these costs are reflected in Staff's direct filing test period. This event was and continues to be a significant activity for Empire. Empire should correct this situation quickly. Until such time, Staff has included an estimate in its current recommendation to reflect the cost associated with this proposed transaction and will update throughout this case as more information becomes available.

Staff Expert/Witness: Amanda C. McMellen

B. Renewable Energy Standard ("RES") Summary

The Missouri Renewable Energy Standard ("RES")[92] was enacted as a voter initiative petition in November 2008. Provisions of the resulting statute and regulations require Empire (and the other investor-owned utilities) to meet certain requirements regarding the use of renewable energy while not exceeding the one percent (1%) retail rate impact limit. The RES requires Empire to provide a rebate to its retail customers for installation of solar electric systems on their premises. Empire was previously believed to be exempt from offering solar rebates to its customers and exempt from the solar RES requirements. The exemption was challenged and on February 10, 2015, the Missouri Supreme Court issued an opinion that Empire was not exempt from these requirements. This resulted in Empire filing proposed solar rebate tariff sheets to offer solar rebates to its customers on May 5, 2015, that became effective May 16, 2015.[93] Because the opinion was not issued until 2015, Empire did not retire solar Renewable Energy Credits ("RECs") for compliance year 2014. Commission rule 4 CSR 240-20.100(3)(J), allows a utility to retire RECs in January, February, and March following the calendar year for which compliance is being achieved, and receive credit in the compliance year. Theoretically, Empire could have retired solar RECs in 2015 for 2014 compliance, but this was probably not practical with the timing of the opinion.

For calendar years 2014 through 2017, the RES requires Empire to generate or purchase five percent (5%) of its retail sales using renewable energy resources.[94] Empire must derive two percent (2%) of the renewable energy requirement from solar energy.[95] RECs can be banked for three (3) years and utilized for future compliance purposes.[96] Empire files annually a RES Compliance Plan and RES Compliance Report.[97] Each RES Compliance Plan provides information regarding the utility's plan for the current calendar year and the subsequent two (2) calendar years. The RES Compliance Report is a status report on the utility's compliance for the

[92] Mo. Rev. Stat. § 393.1020 (2000).

[93] See Case No. ET-2015-0285.

[94] Mo. Rev. Stat. § 393.1030 .1(1) (2000).

[95] Mo. Rev. Stat. § 393.1030.1 (2000).

[96] "An unused credit may exist for up to three years from the date of its creation." Mo. Rev. Stat. § 393.1030.2 (2000).

[97] Empire filed its RES Plan for 2014-2016 and its RES Report for calendar year 2014 in EO-2015-0260; Its 2015 RES Plan and RES Report is due on April 15.

preceding calendar year. For the 2014 calendar year, Empire utilized renewable energy and RECs from Ozark Beach Hydroelectric Project for the non-solar requirement.[98]

Staff Expert/Witness: Claire M. Eubanks, PE

Appendices:

Appendix 1: Staff Credentials

Appendix 2: Support for Staff Cost of Capital Recommendation

Appendix 3: Alphabetical Listing of Testimony Schedules

[98] EO-2015-0260, *2014 Annual Renewable Energy Standard Compliance Report*, pg 4-5.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2016-0023

AFFIDAVIT OF ALAN J. BAX

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW ALAN J. BAX and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Alan J. Bax

ALAN J. BAX

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24th day of March 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D. Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2016-0023

AFFIDAVIT OF MICHELLE A. BOCKLAGE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW MICHELLE A. BOCKLAGE and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Michelle A Bocklage
MICHELLE A. BOCKLAGE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24th day of March 2016.

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Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric	)	
Company's Request for Authority to	)	Case No. ER-2016-0023
Implement a General Rate Increase for	)	
Electric Service	)	

AFFIDAVIT OF KIMBERLY K. BOLIN

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

COMES NOW KIMBERLY K. BOLIN and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Kimberly K. Bolin
KIMBERLY K. BOLIN

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Notary Public

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OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2016-0023

AFFIDAVIT OF KORY BOUSTEAD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW KORY BOUSTEAD and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Kory Boustead
KORY BOUSTEAD

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In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2016-0023

AFFIDAVIT OF KIM COX

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW KIM COX and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Kim Cox

KIM COX

JURAT

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D Suzie Mankin

Notary Public

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OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2016-0023

AFFIDAVIT OF CLAIRE M. EUBANKS, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW CLAIRE M. EUBANKS and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Claire M Eubanks

CLAIRE M. EUBANKS, PE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24th day of March 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
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D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

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AFFIDAVIT OF BRAD J. FORTSON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW BRAD J. FORTSON and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Brad J Fortson

BRAD J. FORTSON

JURAT

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D. SUZIE MANKIN
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State of Missouri
Commissioned for Cole County
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D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

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In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2016-0023

AFFIDAVIT OF KEITH D. FOSTER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW KEITH D. FOSTER and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

KEITH D. FOSTER

JURAT

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AFFIDAVIT OF JERMAINE GREEN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW JERMAINE GREEN and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

JGreen
JERMAINE GREEN

JURAT

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Commissioned for Cole County
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DSuzieMankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2016-0023

AFFIDAVIT OF SHANA GRIFFIN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW SHANA GRIFFIN and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Shana Griffin

SHANA GRIFFIN

JURAT

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AFFIDAVIT OF JENNIFER K. GRISHAM

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW JENNIFER K. GRISHAM and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Jennifer K. Grisham

JENNIFER K. GRISHAM

JURAT

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D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
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D Suzie Mankin

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AFFIDAVIT OF PAUL R. HARRISON

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW PAUL R. HARRISON and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Paul R. Harrison

PAUL R. HARRISON

JURAT

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Commissioned for Cole County
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D Suzie Mankin

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AFFIDAVIT OF ROBIN KLIETHERMES

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW ROBIN KLIETHERMES and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

ROBIN KLIETHERMES

JURAT

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State of Missouri
Commissioned for Cole County
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D Suzie Mankin
Notary Public

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AFFIDAVIT OF SARAH L. KLIETHERMES

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW SARAH L. KLIETHERMES and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Sarah L. Kliethermes

SARAH L. KLIETHERMES

JURAT

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AFFIDAVIT OF SHAWN E. LANGE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW SHAWN E. LANGE and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Shawn E. Lange
SHAWN E. LANGE

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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 The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2016-0023

AFFIDAVIT OF ERIN L. MALONEY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW ERIN L. MALONEY and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

ERIN L. MALONEY

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24th day of March 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2016-0023

AFFIDAVIT OF AMANDA C. McMELLEN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW AMANDA C. McMELLEN and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Amanda C McMellen

AMANDA C. McMELLEN

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24th day of March 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
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D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2016-0023

AFFIDAVIT OF CHARLES T. POSTON, PE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW CHARLES T. POSTON and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

CHARLES T. POSTON, PE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24th day of March 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2016-0023

AFFIDAVIT OF JOHN A. ROBINETT

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW JOHN A. ROBINETT and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

John A. Robinett
JOHN A. ROBINETT

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24th day of March 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2016-0023

AFFIDAVIT OF DAVID C. ROOS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW DAVID C. ROOS and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

David C. Roos

DAVID C. ROOS

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24th day of March 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2016-0023

AFFIDAVIT OF ASHLEY R. SARVER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW ASHLEY R. SARVER and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Ashley R. Sarver

ASHLEY R. SARVER

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24th day of March 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2016-0023

AFFIDAVIT OF MICHAEL L. STAHLMAN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW MICHAEL L. STAHLMAN and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

MICHAEL L. STAHLMAN

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24th day of March 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2016-0023

AFFIDAVIT OF SEOUNG JOUN WON, PhD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW SEOUNG JOUN WON, PhD and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Revenue Requirement; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Seoung Joun Won

SEOUNG JOUN WON, PhD

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 24th day of March 2016.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2016
Commission Number: 12412070

D Suzie Mankin

Notary Public