BEFORE THE PUBLIC SERVICE COMMISSION
STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service.	))))	**Case No. ER-2014-0258** Tariff No. YE-2015-0003

STAFF'S INITIAL POST-HEARING BRIEF

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COMES NOW the Staff of the Missouri Public Service Commission, by and through counsel, and for its *Initial Post-Hearing Brief,* states as follows:

INTRODUCTION

In this general rate case, the Commission exercises its delegated, quasi-legislative authority to set prospective rates for Ameren Missouri ("AmMo"), a major public utility. This decision will affect the lives of thousands of Missourians who live and work within AmMo's service area. It will affect the profitability – indeed, the viability – of numerous small businesses and determine, in part, how much of the family budget will be available for other needs and wants. The Commission's lodestar is the "just and reasonable" rate, which is a rate that produces sufficient revenue to cover AmMo's costs in providing electric service, allows its shareholders a reasonable opportunity to earn a fair return on their investment, and yet is as affordable as possible for the rate-paying public.[1]

The Company:

AmMo is a traditional, integrated electric utility serving approximately 1.2 million customers, over 1 million of which are residential customers.[2]

[1] Sections 393.130 and 393.140, RSMo.

[2] Moehn Direct, pp. 3-4.

AmMo's service territory includes 61 Missouri counties and over 500 towns and cities.[3] To serve its customers, AmMo owns and operates four large, base-load, coal-fired generating plants with a combined capacity of approximately 5,500 megawatts ("MW"); one nuclear-fueled generating plant with a capacity of 1,200 MW; 44 oil-fired or natural-gas-fired combustion turbine generating units ("CTGs") with a combined capacity of about 3,000 MW; and three hydroelectric generating plants with a combined capacity of about 820 MW.[4] AmMo also operates a 15 MW facility powered by landfill gas; 102 MW of wind-produced energy; and is building a 5.7 MW solar facility.[5] AmMo operates and maintains 33,000 miles of distribution lines, 900 distribution substations, and 2,900 miles of transmission lines.[6] The Company employs over 4,000 persons.[7] Ameren Missouri is a wholly-owned subsidiary of Ameren Corporation, a publicly-traded, public utility holding company headquartered in St. Louis, Missouri.

Ratemaking:

The Commission's statutory duty is, after due consideration of all relevant factors,[8] to set "just and reasonable" rates.[9] A "just and reasonable" rate is one

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[3] *Id.,* p. 4.

[4] *Id.,* p. 3.

[5] *Id.,* pp. 3-4. The wind energy facility is located in Iowa.

[6] *Id.,* p. 4.

[7] *Id.*

[8] ***State ex rel. Utility Consumers Council of Missouri, Inc. v. Public Service Commission,*** 585 S.W.2d 41, 49 (Mo. banc 1979) ("Even under the file and suspend method, by which a utility's rates may be increased without requirement of a public hearing, the commission must of course consider all relevant factors including all operating expenses and the utility's rate of return, in determining that no hearing is required and that the filed rate should not be suspended.").

that balances the interests of the various stakeholders in the light of the public interest.[10] A just and reasonable rate is fair to both the utility and to its customers[11] and is no more than is necessary to "keep public utility plants in proper repair for effective public service, [and] . . . to insure to the investors a reasonable return upon funds invested."[12] A just and reasonable rate is not one penny more than is required to cover the utility's necessary and prudent operation and maintenance expenses and to allow a reasonable opportunity of earning a fair profit to the shareholders.

The Commission sets just and reasonable rates via a two-step process using traditional cost-of-service ratemaking.[13] The two steps are (1) the determination of the "revenue requirement," that is, the amount of income the utility needs on an annual basis, and (2) the design of rates that, given the usage characteristics of the utility's customers, will produce the necessary revenue. "Under cost-of-service ratemaking, rates are designed based on a [utility's] cost of providing service including an opportunity for the [utility] to earn a reasonable return on its investment."[14] The Missouri Court of Appeals has described cost-of-service ratemaking as follows: "The Commission [considers the]

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[9] Sections 393.130 and 393.140, RSMo.

[10] *See* ***State ex rel. Union Electric Co. v. Public Service Commission,*** 765 S.W.2d 618, 622 (Mo. App., W.D. 1988) ("Ratemaking is a balancing process").

[11] ***St. ex rel. Valley Sewage Co. v. Public Service Commission,*** 515 S.W.2d 845 (Mo. App., K.C.D. 1974).

[12] ***St. ex rel. Washington University et al. v. Public Service Commission,*** 308 Mo. 328, 344-45, 272 S.W. 971, 973 (banc 1925).

[13] Also known as "rate-of-return" ratemaking. *See* L.E. Alt, ***Energy Utility Rate Setting,*** 18 (2006).

[14] FERC, ***Cost-of-Service Rates Manual,*** 1 (1999) [available electronically at www.ferc.gov].

expenses and revenues, to establish a rate that will allow the company to recover its cost of service from its customers."[15] Elsewhere, the court noted:

> The determination of utility rates focuses on four factors. These factors include: (1) the rate of return the utility has an opportunity to earn; (2) the rate base upon which a return may be earned; (3) the depreciation costs of plant and equipment; and (4) allowable operating expenses. The revenue allowed a utility is the total of approved operating expenses plus a reasonable rate of return on the rate base. The rate of return is calculated by applying a rate of return to the cost of property less depreciation. The utility property upon which a rate of return can be earned must be utilized to provide service to its customers. That is, it must be used and useful. This used and useful concept provides a well-defined standard for determining what properties of a utility can be included in its rate base.[16]

This ratemaking recipe is often expressed by the following formula:

$$\mathbf{RR = C + (V - D)\,R}$$

where:	RR	=	Revenue Requirement;
	C	=	Prudent Operating Costs, including Depreciation Expense and Taxes;
	V	=	Gross Value of Utility Plant in Service;
	D	=	Accumulated Depreciation; and
	R	=	Overall Rate of Return or Weighted Average Cost of Capital (WACC).

To summarize, cost-of-service ratemaking establishes the utility's cost of providing service on an annual basis based upon annualized and normalized test year expenses and adds to that amount a reasonable allowance for a profit to the shareholders on the value of their investment. The profit allowance, in turn, is calculated by multiplying the value of the utility's plant-in-service less accumulated depreciation by a rate of return. This sum is the revenue

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[15] ***State ex rel. Laclede Gas Company v. Public Service Commission,*** 328 S.W.3d 316, 317 (Mo. App., W.D. 2010).

[16] ***Union Electric Co.,*** *supra,* 765 S.W.2d at 622.

requirement, that is, the amount of money the company must earn annually to cover its cost of service and provide a reasonable return to its investors. Determining the revenue requirement is the first half of the ratemaking process.[17]

In considering the Company's test year expenditures, the Commission should consider whether they are reasonable, necessary and beneficial to ratepayers. Unreasonable and unnecessary expenditures should be excluded from rates and charged to the shareholders. An expenditure is reasonable if the value received is commensurate to the amount paid. An expenditure is necessary if, without it, the utility's ability to provide safe and adequate services to its customers would be impaired. Likewise, expenditures that provide no benefits to the ratepayers should be excluded from rates and charged to the shareholders.

Likewise, the Commission should consider whether the Company's expenditures are lawful and prudent. Unlawful and imprudent expenditures should also be excluded from rates. An expenditure is unlawful if it violates a statute or regulation or a Commission order or decision. An expenditure is imprudent if it is deleterious to ratepayers and, viewed in the context of what was known or should have been known to the Company's officers at the time the expenditure was made, a reasonably prudent person would not have made it.

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[17] Edison Electric Institute (EEI), ***Rate Shock Mitigation*** (June, 2007) p. 5 ("In simple terms, a utility's cost of service or revenue requirement consists of three primary elements: (1) operating costs, such as fuel costs, purchased power costs, operations and maintenance (O&M) costs and customer service costs; (2) a return of capital cost, otherwise known as depreciation expense; and (3) a return on capital cost, including applicable income taxes.")

The second half of the ratemaking process is rate design, that is, the development of rate schedules designed to produce the target revenue requirement. The two steps of rate design are, first, determining the revenue requirement responsibility of each customer class and, second, adjusting or designing the class rate schedules to produce the necessary revenue requirement. Customers, large and small, are classified based on their usage characteristics and on the cost of serving them.

Rate design may be driven by considerations additional to recovering the necessary revenue requirement in a fair and equitable manner. Learned commentators on the rate design process refer to "objectives" including fairness, simplicity, stability, avoidance of undue discrimination or preferences, efficiency, and conservation.[18] Another consideration in rate design is the avoidance of "rate shock," that is, an increase that is simply too large to be readily accepted by ratepayers.

Fair rates match costs and cost causers, so that similarly-situated customers will pay the same rate. Simple rates are easy to understand and administer. Stable rates will generate revenue that tracks costs, so that as costs go up, revenues will too. Discrimination and preferences are the two sides of the subsidization coin. All utility rates involve some degree of subsidization because the actual cost of serving each customer is necessarily slightly different based on unique circumstances, such as the distance of each customer from the utility

[18] Alt, *supra,* 58-60; J.C. Bonbright *et al., **Principles of Public Utility Rates,*** 85-179 (PUR: Arlington, VA, 2nd ed. 1988).

plant. An important goal in rate design is keeping these subsidies as limited as possible. Efficiency and conservation mean that prices send appropriate cost signals to the customers to safeguard society's scarce resources and to avoid waste.

In summary, Staff urges the Commission to set just and reasonable rates for Ameren Missouri, after due consideration of all relevant factors, by adopting Staff's recommendations as further discussed herein.

--Kevin A. Thompson.

ARGUMENT

1. Weather Normalization Issues:

What level of sales to Noranda should be assumed for the test year for purposes of establishing billing units?

Staff recommends the Commission use normalized test year kWh sales for the LTS class for the purpose of establishing billing units in this case. Staff and Ameren Missouri both found the calculation of the LTS class energy usage during the test year to be approximately 4.3 billion kWh.[19,20] Ameren Missouri changed its recommendation on the day of the hearing from using a two-month average level of sales of 3.8 billion kWh to a three-year average level of sales of 4.1 billion kWh.[21] While Ameren Missouri's new recommendation is more reasonable than its initial one, Staff's recommendation is still the most

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[19] S. Kliethermes Surrebuttal, p. 32, ll. 21 & 22.

[20] This level of sales corresponds to a 98.2% load factor.

[21] This level of sales corresponds to a 97% load factor.

reasonable recommendation for the purpose of establishing billing units in this case.

Staff's recommendation is the most reasonable in this case because as stated by MIEC witness Phillips, Noranda's electricity usage declined in mid-2014 as a result of higher than normal pot failures but Noranda intends to be back at full production by the end of March 2015.[22] While it is certainly true that the abnormal amount of pot failures Noranda experienced in the latter half of 2014 resulted in lower revenues for Ameren Missouri, this Commission is obligated to set rates prospectively using the best available data it has at its disposal. Using a three-year average level of sales may seem reasonable and in many cases is reasonable; however, since Ameren Missouri's proposed average level of sales for establishing billing units includes the abnormal pot failures, which Noranda has stated will be resolved by the end of March of 2015, it is unreasonable to use this average to establish billing units in this case.

If the Commission accepts Ameren Missouri's recommendation of using a three- year average of Noranda's load factor, then when Noranda resumes buying electricity at test year levels, which it has stated it intends to do, it will amount to an over-earnings of approximately $2 million dollars per year.[23] MIEC's witness Phillips agrees with Staff's recommendation that the LTS class billing determinates be set using test year levels of demand and energy.[24] As stated by Ameren's own witness, Noranda's load has already partially

[22] Phillips Surrebuttal, p. 4, ll. 6-11.

[23] Steven M. Wills, Tr. 16:260, ll. 5-11.

[24] Phillips Surrebuttal p. 4, ll. 14 & 15.

returned to test year levels in the first two month of this year.[25] Because Noranda's reduction in purchases in the second half of 2014 was due to abnormal levels of pot failures and because Noranda has indicated that it expects to resume test year levels of electricity purchases by the end of March 2015, Staff recommends using normalized test year levels of billing units for the LTS class.

--Alexander Antal

2. Income Tax Issues:

A. Should Ameren Missouri's Net Operating Loss Carryforward related to ADIT be included in Ameren Missouri's rate base?

Staff recommends that Ameren Missouri's Net Operating Loss Carryforward ("NOLC") related to ADIT be included in its rate base, but only on a stand-alone basis. Staff recommends calculating the NOLC on a stand-alone basis in this case to ensure that the tax allocation agreement between Ameren Corporation and its various affiliates, including Ameren Missouri, does not detrimentally affect Ameren Missouri's ratepayers.

Calculating Ameren Missouri's NOLC on a stand-alone basis reduces rate base by $31 million. That is to say Ameren Missouri would have had $31 million in additional cost-free capital had it filed it taxes on a stand-alone basis as opposed to a consolidated basis.[26] So, as a result of the tax allocation agreement, which Ameren Missouri entered into with Ameren Corporation and its various affiliates, Ameren Missouri, argues that it must be able to collect this

[25] Steven M. Wills, Tr. 16:253, ll. 21-25.

[26] James Warren, Tr. 16:345, ll. 6-14.

additional revenue from its ratepayers. Ameren Missouri entered into the tax allocation agreement because this tax status resulted in significant benefits to Ameren Missouri, Ameren Corporation and its various other affiliates. Yet while this agreement confers benefits to Ameren Missouri it has resulted in at least this one instance in a considerable detriment to Ameren Missouri's ratepayers. The cause of this considerable detriment was Ameren Corporation's decision to divest itself of its merchant generating affiliate, which created extremely large tax losses to be allocated to the remaining affiliates under the tax allocation agreement.[27] The Commission should hold Ameren Missouri's ratepayers harmless as it was not their decision to enter into a tax agreement that would result in a net operating loss of one of Ameren Missouri's unregulated affiliates being allocated to Ameren Missouri triggering a $31 million increase in rate base.

In general, utility holding companies have many opportunities to structure transactions and relationships between the utility and its unregulated affiliates in a way that can increase revenue requirements to the detriment of ratepayers.[28] This opportunity for gain to the holding company at the detriment of ratepayers is one of the principle reasons public service commissions exist and is why this Commission is obligated to ensure that the transactions and relationships that Ameren Missouri has with Ameren Corporation do not detrimentally affect Ameren Missouri ratepayers.

> To prevent injury to the public, in the clashing of private interest with the public good in the operation of public utilities, is

[27] Michael L. Brosch, Tr. 16:387, ll. 22-25.

[28] Michael L. Brosch, Tr. 16:385, ll. 7-12.

> one of the most important functions of Public Service Commissions. It is not their province to insist that the public shall be benefited, as a condition to change of ownership, but their duty is to see that no such change shall be made as would work to the public detriment. 'In the public interest,' in such cases, can reasonably mean no more than 'not detrimental to the public.' "[29]

MIEC agrees with Staff that Ameren Missouri's NOLC related to ADIT be included in its rate base, but only on a stand-alone basis. MIEC supports this recommendation on the basis that general regulatory policy requires that utilities and their ratepayers not be disadvantaged by the structure of transactions with its affiliate companies, and that this general regulatory policy is consistent with this Commission's affiliate transaction rule.[30] Now Staff has not taken an official position in this case as to whether Ameren Missouri's tax allocation agreement with Ameren Corporation and its various affiliates is applicable to, and if so, in violation of the Commissions affiliate transaction rule. Staff has requested in this case, and Ameren Missouri has agreed to seek Commission approval of the Company's Cost Allocation Manual ("CAM") in its next rate case. Since the tax allocation agreement has never been approved by the Commission Staff intends to thoroughly vet the tax allocation agreement as part of the CAM approval process in the next rate case to determine its applicability to the Commission's affiliate transaction rule and if so whether it is in compliance with the rule.

Nevertheless, Staff believes that the current tax allocation agreement has a detrimental impact on Ameren Missouri ratepayers as it allocates a significantly

[29] ***State ex rel. City of St. Louis v. Public Service Commission,*** 73 S.W.2d 393 (Mo. 1934) (citing to ***Electrical Public Utilities Co. v. West,*** 140 Atl. 840 (Md. 1928).

[30] Michael L. Brosch, Tr. 16:384, ll. 10-16.

higher amount of NOLC to Ameren Missouri which reduces the amount of ADIT or cost free capital Ameren Missouri has, which in turn increases rate base, which will increase the rates Ameren Missouri's ratepayers pay for electricity. For this case, Staff is recommending that Ameren Missouri's NOLC related to ADIT be included in its rate base, but only on a stand-alone basis to avoid the detrimental impact the tax allocation agreement will have on ratepayers. As stated by Ameren Missouri's own witness there is no tax law that prohibits this Commission from calculating Ameren Missouri's NOLC related to ADIT on a stand-alone basis when Ameren Missouri files its income taxes on a consolidated basis so long as its decision is not arbitrary and capricious.[31] This rate treatment is well within the Commission's authority and is in keeping with the Commission's obligation to protect the public interest from the detrimental affect transactions and relationships between regulated public utilities and their unregulated holding companies. For these reasons Staff recommends that Ameren Missouri's NOLC related to ADIT be included in its rate base, but only on a stand-alone basis.

B. Should the Company's IRC Section 199 deduction be computed without regard to Net Operating Loss Carryovers from prior years in determining the company's income tax expense?

Staff recommends that Ameren Missouri's IRC section 199 deduction be computed without regard to NOLC from prior years; however, Staff asserts, if NOLC is included then the deduction should only be computed on a stand-alone basis. Staff recommends calculating the section 199 deduction not include NOLC from prior years because this has been the methodology used to calculate

[31] James Warren, Tr. 16:346, ll. 11-17.

the Company's Section 199 deduction in its past rate cases.[32] Ameren Missouri's initial true-up data included an amount of **__________ ** for the section 199 deduction; however, the revised true-up data, which was not provided until February 3, 2015, included an amount of **__** for the section 199 deduction.[33] Ameren Missouri has argued that its past methodology, which did not include NOLC for calculating its section 199 deduction, was in error and its new calculation submitted to Staff seven months into this rate case was a correction.[34] Staff agrees with MIEC that there is nothing inherently incorrect with the method Ameren Missouri has used to calculate its section 199 deduction in past rate cases and, in fact, it should be the preferred method because none of the parties to this case can anticipate with any accuracy whether during the period rates are in effect Ameren Missouri will have a net operating loss.[35] For these reasons Staff recommends disregarding NOLC from prior years in calculating Ameren Missouri's section 199 deduction.

If the Commission is to allow Ameren Missouri to make this alleged correction to the section 199 deduction it should only allow the deduction to be calculated on a stand-alone basis. Staff recommends calculating the section 199 deduction on a stand-alone basis if the Commission allows the Company to include NOLC from prior years because this methodology holds ratepayers harmless for Ameren Missouri choosing to file a consolidated tax return. Staff's

[32] Hanneken Surrebuttal, p. 15, ll. 2-3.

[33] Hanneken Surrebuttal, p. 14, ll. 10-13.

[34] James Warren, Tr. 16:341, ll. 9-11.

[35] Michael L. Brosch, Tr. 16:411, ll. 3-6.

recommendation for why the Commission should only allow Ameren Missouri to include NOLC in its calculation of its section 199 deduction is based on the same rationale as Staff's recommendation for why NOLC related to ADIT should be calculated on a stand-alone basis; principally, because the tax allocation agreement has a detrimental effect on Ameren Missouri ratepayers. While the tax allocation agreement may have conferred a benefit to Ameren Missouri ratepayers in the past, this agreement has never been approved by the Commission. Until such time that the Commission has an opportunity to approve the tax allocation agreement, which will be part of the Company's CAM approval in the next rate case, the Commission should not allow the tax allocation agreement to influence rates in a way that causes a detriment to the public interest. For this reason Staff asserts that if the Commission allows the Company to include NOLC from prior years in the calculation of its section 199 deduction it should only do so on a stand-alone basis.

--Alexander Antal.

3. Amortizations:

A. Should the amount of solar rebates paid by Ameren Missouri and recorded to a solar rebate regulatory asset through the end of the true-up period be included in Ameren Missouri's revenue requirement using a 3-year amortization period?

Yes. By its *Order Approving Stipulation and Agreement* issued on November 13, 2013[36], in Case No. ET-2014-0085, the Commission approved a *Non-Unanimous Stipulation and Agreement* ("Stipulation") signed by AmMo;

[36] Ex. 243.

Staff; the Office of the Public Counsel; the Missouri Division of Energy; Missouri Solar Energy Industries Association; Brightergy, LLC; Earth Island Institute d/b/a Renew Missouri; and the Missouri Industrial Energy Consumers.[37] Paragraph 7.d of the Stipulation provided that:

> Solar rebate amounts paid by Ameren Missouri after July 31, 2012, including the additional amount provided for in the immediately following sentence, shall be included in a regulatory asset to be considered for recovery in rates after December 31, 2013, in a general rate case. Ameren Missouri shall record to the regulatory asset the actual dollar amount of solar rebates paid, not to exceed $91.9 million, from August 1, 2012 through the later of (i) the end of the test year, (ii) the end of the test year update period or (iii) the end of the true-up period in Ameren Missouri's next general rate proceeding, plus ten percent (10%) of that amount. If Ameren Missouri has not paid $91.9 million in solar rebates from August 1, 2012 through the later of (i), (ii) or (iii) above in Ameren Missouri's next general rate proceeding, then one or more additional regulatory assets shall be subsequently reflected on Ameren Missouri's books to record additional solar rebated payments made by Ameren Missouri equaling the difference between the amount of solar rebate payments deferred in the initial regulatory asset and $91.9 million, plus 10% of the amount of those additional deferred solar rebate payments. The Signatories agree not to argue that the solar rebate payments should have been suspended in 2013. Ameren Missouri agrees solar rebate payments and the additional amount provided for above will only be reflected in a general rate proceeding and *recovered in a general rate case through a three-year amortization*, and cannot be included in a Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM"). The regulatory asset provided for in this subparagraph d shall not include any additional sums, and *no return*, carrying costs or income tax mark-up *shall be allowed on the unamortized balance*. Upon the Commission's approval of this Agreement, the balance of the regulatory asset provided for by this subparagraph d shall be reduced by an amount equal to the cumulative interest recorded by Ameren Missouri related to solar rebates paid since August 1, 2012. *The Signatories agree not to object to Ameren Missouri's recovery in retail rates of prudently paid solar rebates [footnote] and the additional amount provided for above. The Signatories reserve*

[37] Ex. 55

> *the right to raise issues related to whether the solar rebates were prudently paid in future general rate cases*.[38] (Emphasis added)

The footnote to the above quotation further provided that:

> Given the Signatories' agreement that the specified amount should be paid, *the only questions in future general rate proceedings regarding the recovery of solar rebate payments is whether the claimed solar rebate payments have been made and whether they were prudently paid* under the Commission's RES rules and Ameren Missouri's tariff. "Prudently paid" relates only to whether Ameren Missouri paid the proper amount due to an application for a rebate, paid it to the proper person or entity, and paid it in accordance with the Commission's RES rules and Ameren Missouri's tariffs.[39] (Emphasis added)

As a Signatory to the foregoing Stipulation, Staff developed its position in this case to be consistent with the Stipulation. Staff has determined that through the December 31, 2014 true-up cutoff date established by the Commission in this rate case Ameren Missouri deferred and accumulated in a regulatory asset account $88,133,149 for solar rebates.[40] Coupled with the 10% cost adder of $8,813,314.90, Ameren Missouri is eligible to seek recovery of $96,946,463.90 over a three year amortization period.[41] There was no question whether the claimed solar rebate payments had been made or whether they were prudently paid. Therefore, in accordance with the Stipulation, Staff recommends that $32,315,488 in amortization expense be reflected in the revenue requirement cost of service calculation and that this amortization begin on the operation-of-

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[38] *Id.*

[39] *Id.* at Footnote 7

[40] Ex. 57; see also Ex. 211, p. 4

[41] *Id.*

law date established by the Commission in this rate case.[42] Furthermore, consistent with the Stipulation, no return should be allowed on the unamortized balance (*i.e.,* no rate base treatment on the unamortized balance).[43]

B. Should the amount of pre-MEEIA energy efficiency expenditures incurred by Ameren Missouri and recorded to a regulatory asset through the end of the true-up period be included in Ameren Missouri's revenue requirement and, if so, over what period should they be amortized?

Unlike the solar rebate amortization issue discussed above and the Fukushima study amortization issue discussed below, the energy efficiency ("EE") amortizations issue has both a rate base aspect and an expense aspect.

Rate Base

Prior to this rate case, AmMo had four existing demand side management EE regulatory asset amortizations which were implemented in previous rate cases.[44] These four EE amortizations were created in Case Nos. ER-2008-0318, ER-2010-0036, ER-2011-0028, and ER-2012-0166.[45] The last three of the four previously-existing EE amortizations were each originally for 6 years.[46] The unamortized balances of three (the last three) of these four amortizations were also previously included in rate base to allow AmMo a return on the unrecovered

[42] *Id*.; see also Tr. 587.

[43] Ex. 55

[44] Ex. 202, p. 122

[45] *Id.* at p. 58

[46] Ex. 202 p. 58

balances.[47] Accordingly, Staff has included the unamortized portions of each of these three EE amortizations in rate base.[48]

As part of this case, AmMo has proposed to initiate a fifth EE amortization to address demand side management deferred pre-MEEIA program costs incurred after the true-up cutoff date of AmMo's most recent prior rate case.[49] Consistent with the ratemaking treatment established for these costs for AmMo's last three EE amortizations, Staff has included a 6-year amortization of the deferred pre-MEEIA program costs incurred after the true-up cutoff date in the prior rate case and also included the unamortized balance of this new EE amortization in rate base[50] along with the three previously-existing EE amortizations which are included in rate base, and recommends the Commission so order.

Expense

In this case, Staff recommends that the EE amortization established in Case No. ER-2010-0036 be "reset" because it is scheduled to expire in July 2016 and AmMo would over-recover for this amortization unless it filed another rate case no later than August 2015.[51] Therefore, Staff recommends that this amortization be reset to provide recovery over a two-year period beginning with

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[47] *Id.* at p. 122 (correction at Tr. 530 changed "each" to "three"). The previous EE amortization which was *not* included in rate base was the 10-year amortization created in Case No. ER-2008-0318; see Ex. 202 p. 58.

[48] Ex. 202 p. 58

[49] *Id.* at 123. As of the December 31, 2014 true-up cutoff date established by the Commission in this rate case, there was approximately a $3.5 million balance of deferred pre-MEEIA program costs that were incurred since the true-up cutoff point in the last case. See Ex. 40 p. 11.

[50] *Id.*

[51] Ex. 202 pp. 122-123

the effective date of rates in this rate case.[52] All other previously-existing EE amortizations were unadjusted by Staff[53], *i.e.*, Staff recommends that they continue to be amortized as previously ordered. In regard to the new EE amortization proposed by AmMo to be established in this case, as stated above, to be consistent with the ratemaking treatment established for these costs for AmMo's last three EE amortizations Staff has included a 6-year amortization of the deferred pre-MEEIA program costs incurred after the true-up cutoff date in the prior rate case[54] and accordingly recommends the Commission order a 6-year amortization of these costs beginning with the effective date of rates in this rate case.

Staff would also note that, in addition to being consistent with the ratemaking treatment previously established for these costs, Staff believes that its recommended treatment in regard to both the rate base and expense aspects is consistent with what was referred to at the hearing as the state policy to encourage the recovery of energy efficiency costs.[55] Staff recommends the Commission adopt both Staff's rate base and expense treatment of this issue as set out above.

C. Should the amount of Fukushima flood study costs incurred by Ameren Missouri and recorded to a regulatory asset be included in Ameren Missouri's revenue requirement and, if so, over what period should they be amortized?

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[52] *Id.* at 123; Ex. 209 p. 13

[53] Ex. 209 p. 13

[54] Ex. 202 p. 123

[55] Tr. p. 600

What has been referred to in this case as the “Fukushima study” or “Fukushima flood study” was a study undertaken by AmMo which was mandated by the Nuclear Regulatory Commission (“NRC”) of utilities with nuclear power plants after the Fukushima nuclear incident.[56] Since the study was mandated by the NRC, Staff recommends that $926,561 of the costs incurred by AmMo for the Fukushima study be reflected as a regulatory asset and amortized over a ten-year period beginning with the effective date of rates in this rate case.[57] This results in an amortization expense amount of $92,656 to be reflected in the revenue requirement cost of service calculation[58] with no return to be allowed on the unamortized balance (*i.e.,* no rate base treatment on the unamortized balance).

--Jeffrey A. Keevil

4. Noranda Ice Storm AAO:

Should the sums authorized for deferral in Case No. EU-2012-0027 be included in Ameren Missouri’s revenue requirement and, if so, over what period should they be amortized?

Introduction:

The Commission should not include any of the amount deferred in Case No. EU-2012-0027 in Ameren Missouri’s revenue requirement. Why? Because the deferred amount represents fixed costs not paid by the rate revenue collected at the time. Now, years later, Ameren Missouri demands additional revenue from

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[56] Tr. pp. 509, 599-600; Ex. 202, pp. 121-122

[57] Ex. 202, p. 122; Ex. 209, p. 14; True-up Accounting Schedules Ex. 241, Accounting Schedule 10 Adjustment E-203

[58] True-up Accounting Schedules Ex. 241, Accounting Schedule 10 Adjustment E-203

its ratepayers to cover that loss. This is classic retroactive ratemaking; it is unlawful and cannot be allowed.

The Missouri Supreme Court has said that the Commission "may not . . . redetermine rates already established and paid without depriving the utility (or the consumer if the rates were originally too low) of his property without due process."[59] The Court further stated, "[t]he utilities take the risk that rates filed by them will be inadequate, or excessive, each time they seek rate approval. To permit them to collect additional amounts simply because they had additional past expenses not covered by either clause is retroactive rate making, i.e., the setting of rates which permit a utility to recover past losses or which require it to refund past excess profits collected under a rate that did not perfectly match expenses plus rate-of-return with the rate actually established[.]"[60] The effect of the ice storm in January 2009 that interrupted service to Noranda was to make Ameren Missouri's rates too low, so that the revenue actually collected from the LTS class did not cover all of the fixed costs assigned to that class. By attempting *now* to collect additional revenue from ratepayers for the fixed costs it incurred *then,* Ameren Missouri is asking the Commission to do exactly what the Supreme Court held it could not do. For that reason, the Commission must deny rate recovery of the amount deferred in Case No. EU-2012-0027.

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[59] ***State ex rel. Utility Consumers' Council of Missouri, Inc. v. Public Service Commission,*** 585 S.W.2d 41, 58 (Mo. banc 1979) (***"UCCM"***).

[60] ***UCCM,*** 585 S.W.2d at 59.

Background of the Issue:

In January 2009, a severe ice storm in Southeast Missouri interrupted service to Noranda Aluminum's smelter at New Madrid, Missouri.[61] As a result, the smelter was able to buy only about a third of the expected amount of service from Ameren Missouri for a period of some fourteen months, between February 2009 and April 2010.[62] Consequently, Ameren Missouri did not receive anticipated revenues from Noranda of some $58 million.[63] Because Noranda was the Company's largest single customer and accounted for about eleven percent of its total load,[64] the loss of two-thirds of the revenues anticipated from Noranda was a significant financial loss to the Company.[65]

To replace the lost Noranda revenue, Ameren Missouri entered into power contracts with AEP and Wabash.[66] However, Staff maintained that the AEP-Wabash revenue was off-system sales revenue ("OSSR") and thus subject to the sharing mechanism in Ameren Missouri's Fuel Adjustment Clause ("FAC").[67] In Cases EO-2010-0255 and EO-2012-0074, the Commission agreed with Staff

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[61] Robertson Direct, pp. 4-5.

[62] Lynn Barnes, Tr. 18:713, 738.

[63] Lynn Barnes, Tr. 18:736; John Cassidy, Tr. 20:770.

[64] Lynn Barnes Rebuttal, p. 60.

[65] Annual revenues from Noranda at the time of the ice storm were approximately $139 million. *Verified Application for Accounting Authority Order,* Case No. EU-2012-0027, p. 3.

[66] *Prudence Review of Costs Related to the Fuel Adjustment Clause for the Electric Operations of Union Electric Company, d/b/a AmerenUE, March 1, 2009 through September 30, 2009,* Case No. EU-2010-0255, pp. 17-18.

[67] *Id.* Off-system sales revenue ("OSSR") is subject to a 95/5 percent sharing mechanism under Ameren Missouri's FAC, whereby 95% of any such revenues are used to reduce the fuel costs otherwise borne by the ratepayers. *Id.,* at 2. The revenue anticipated from Noranda, on the other hand, was part of Ameren Missouri's native retail load and thus not subject to the sharing mechanism.

that the AEP-Wabash revenue was OSSR and thus subject to the sharing mechanism in the FAC; Ameren Missouri was required to refund some $44 million to its ratepayers. The Commission's decision in Case No. EO-2010-0255 was upheld by the Missouri Court of Appeals.[68]

In July 2011, following the Commission's decision in Case No. EO-2010-0255,[69] Ameren Missouri filed an application for an Accounting Authority Order ("AAO"),[70] docketed as Case No. EU-2012-0027, "addressing the Company's accounting for fixed costs it has been unable to recover due to an extraordinary, unanticipated, and devastating ice storm that struck Southeast Missouri in late January, 2009."[71] Despite the strenuous opposition of the Staff, the Public Counsel and MIEC, the Commission granted the requested AAO to Ameren Missouri:

> The Missouri Public Service Commission is granting the application for an accounting authority order ("AAO"). The AAO accounts for unexpected lost revenue to recover fixed costs. The AAO only allows for deferred recording, does not guarantee recovery, and does not in any way bind the Commission as to future rate making treatment.[72]

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[68] ***State ex rel. Union Electric Company d/b/a Ameren Missouri v. Public Service Commission,*** 399 S.W.3d 467 (Mo. App., W.D. 2013).

[69] *Report & Order* issued April 27, 2011, in which the Commission first determined that the AEP-Wabash revenue was subject to the sharing mechanism in the FAC.

[70] The Commission has stated, "An AAO is a mechanism to "defer" an item, which means to record an item to a period outside of a test year for consideration in a later rate action. Items eligible for deferral include an "extraordinary item", an item that pertains to an event that is extraordinary, unusual and infrequent, and not recurring." *Report & Order,* Case No. EU-2012-0027, issued November 26, 2013, p. 3 (footnotes omitted).

[71] *Verified Application for Accounting Authority Order,* Case No. EU-2012-0027, p. 1.

[72] [72] *Report & Order,* Case No. EU-2012-0027, issued November 26, 2013, p. 1. Affirmed, *per curiam,* ___ S.W.3d ___, 2015 WL 160636 (Jan. 13, 2015).

Pursuant to this authority, Ameren Missouri deferred $35,561,503.[73] In the present case, the Company proposed to recover this amount in rates over five years, at a rate of $7,112,000 per year.[74]

The Deferred Amount Cannot Be Recovered In Rates:

No part of the $35.5 million deferred in Case No. EU-2012-0027 can be recovered in rates because to allow recovery would violate the prohibition on retroactive ratemaking. According to the Supreme Court, the Commission "may consider past excess recovery insofar as this is relevant to its determination of what rate is necessary to provide a just and reasonable return in the future, and so avoid further excess recovery[.]"[75] The same goes for insufficient recovery, which is the case here. "Past expenses are used as a basis for determining what rate is reasonable to be charged in the future in order to avoid further excess profits or future losses, but under the prospective language of the statutes, §§ 393.270(3) and 393.140(5), **they cannot be used to set future rates to recover for past losses due to imperfect matching of rates with expenses."**[76]

It is important to be mindful that the standard for deferral is not the standard for recovery.[77] A deferral is appropriate where the amount in question is material and results from an extraordinary, non-recurring event outside of the

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[73] Moore Direct, p. 26.

[74] *Id.*

[75] ***UCCM,*** 585 S.W.2d at 58.

[76] *Id.,* at 59 (emphasis added).

[77] There is evidently some confusion on this point. Mr. Mitten stated, "There's also ample evidence in the record in this case as to why recovery of the deferred amounts through rates set in this case is appropriate, and it's the same evidence the company presented and the Commission considered in the AAO case." Tr. 18:649.

Company's control.[78] However, those factors have no relevance whatsoever to the question of recovery. Recovery is ratemaking and the normal ratemaking standards apply. In ratemaking, a deferred amount is only one of countless relevant factors that must be considered.[79]

Recovery of a deferred amount is appropriate where the amount in question is reasonable, necessary, prudent, and beneficial to ratepayers. There is one special caveat that applies to recovery: recovery of a deferred amount is not permitted where it is intended to make the utility whole for a past loss.[80] Therefore, the question that controls here is whether Ameren Missouri is seeking recovery of a past loss – which is forbidden -- or seeking to adjust prospective rates to avoid a future loss – which is permitted. The evidence overwhelmingly shows that Ameren Missouri is seeking to recover a past loss, which is unlawful retroactive ratemaking.[81]

First, Ameren Missouri's counsel admitted as much in his opening statement.[82] Mr. Mitten stated, "Fifteen months ago the Commission issued its *Report and Order* in File No. EU-2012-0027, the case that considered

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[78] *Report & Order,* Case No. EU-2012-0027, p. 3; and see *In the Matter of Missouri Public Service Co.,* 1 Mo.P.S.C.3d 200, 203 (Dec. 20, 1991) (the *Sibley* case). The classic example is an "act of God" such as a storm or tornado.

[79] John Cassidy, Tr. 20:784.

[80] ***UCCM,*** 585 S.W.2d at 58 and 59.

[81] Although the Company characterizes the deferred amounts as lost fixed costs, the Staff continues to maintain that the deferred amounts more appropriately represent lost revenues and therefore lost profits as was explained in Staff witness John Cassidy's rebuttal and surrebuttal testimony. However, to be consistent with the Commission Order in EU-2012-0027, in this brief the Staff will refer to these items as lost fixed costs.

[82] An admission by an attorney against the interests of his client in open court is binding on the client and serves as a substitute for evidence. ***State v. Denzmore,*** 436 S.W.3d 635, 643 (Mo. App., E.D., 2014).

Ameren Missouri's application for **an accounting authority order to cover fixed costs the company was unable to collect when Noranda's New Madrid aluminum smelter curtailed operations for 14 months following a massive ice storm that struck southeast Missouri in January 2009.**"[83] He went on, "the AAO case determined the Commission already has decided the deferred items are revenues needed to cover the company's fixed costs of providing service."[84] In particular, Mr. Mitten stated:

> As for the argument the amounts at issue here already were included in the determination of Ameren Missouri's revenue requirement in a past case, that's correct. But as the company explained in the AAO case and explains again in this case, **it's the fact those amounts were not collected from any customer following that rate case that caused Ameren Missouri to seek an AAO and caused the Commission to authorize one.**[85]

Nowhere does Mr. Mitten characterize the recovery of the deferred amount as anything other than past fixed costs not covered by contemporary revenue. In other words, what Mr. Mitten argued for was "the redetermination of rates already established and paid," which is forbidden as retroactive ratemaking.[86]

Second, Ameren Missouri's fact witness, Lynn Barnes, characterized the deferral in the same terms as Mr. Mitten. She testified, "Ameren Missouri was unable to recover almost $36 million of fixed costs that the Commission had allocated to Noranda in a final rate case order issued just days before the ice storm struck, and which would have been recovered from Noranda in the

[83] Tr. 18:646 (emphasis added).

[84] Tr. 18:649.

[85] Tr. 18:649 (emphasis added).

[86] ***UCCM,*** 585 S.W.2d at 58.

absence of the ice storm."[87] Even more telling, Ms. Barnes testified: "[I]n July 2011 Ameren Missouri promptly filed its application for an AAO to allow the Company to defer its unrecovered fixed costs and to permit it to seek recovery of those costs in its next rate case."[88] At hearing, Ms. Barnes testified, "what we're requesting is the shortfall as a result of the billing rate design assuming a full load for Noranda and not having a full load for 14 months."[89] For Ms. Barnes, like Mr. Mitten, recovery is appropriate because the deferred amount represents unrecovered fixed costs. For Ms. Barnes, "[t]he relevant consideration, as the Commission recognized when it granted the AAO, is that Ameren Missouri was unable to recover these costs due to the extraordinary impact of the 2009 ice storm." Unfortunately, that is not the relevant consideration for recovery of the deferred amount in rates. Unfortunately, what Ms. Barnes seeks is exactly what the law forbids.

Third, the prospective adjustment of Ameren Missouri's rates to account for the possibility of a future extraordinary loss of most of Noranda's load and the associated revenues due to an ice storm is unnecessary because it simply cannot happen again. Ms. Barnes admits as much.[90] That is due to the inclusion in Ameren Missouri's LTS tariff of the "N Factor," which is specifically intended to prevent just this situation in the future:

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[87] Lynn Barnes Rebuttal, p. 61.

[88] Lynn Barnes Rebuttal, p. 61.

[89] Lynn Barnes, Tr. 18:714.

[90] Lynn Barnes, Tr. 18:718.

> The way Factor N works is, if the ice storm were to occur tonight and we had a loss of load in Noranda of a certain level, and I forget the exact level but it's not just any loss, it's a significant loss, that we would be able to retain the revenues from the off-system sales relating to the generation that was not delivered to Noranda up to the point where we would be made whole for that loss, and then any excess revenues, and it's revenues, not sales, so any excess revenues beyond that that we made using that same generation would go back to the customers through the FAC.[91]

In considering this issue, Staff urges the Commission to avoid various conceptual traps laid by the Company. In his opening statement, Mr. Mitten stated, "we have been unable to find any case during the past 50 years where the Commission refused to allow full recovery of amounts deferred through an AAO unless there is evidence the utility was imprudent in connection with the extraordinary event that gave rise to the AAO or there is evidence the amount deferred was incorrect."[92] In fact, that observation is entirely irrelevant. Where, as here, the proposed recovery is unlawful, it does not matter how many other deferrals have been recovered in rates. By far the majority of deferrals are of extraordinary expenses, the recovery of which is favored by public policy. An example would be extraordinary storm restoration costs. Likewise, state commissions only rarely allow a deferral whose recovery would, as in this case, constitute unlawful retroactive ratemaking. Therefore, it is not easy to find parallels to the present case. Certainly, none of the AAOs referred to by Mr. Mitten are at all similar to this one.

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[91] Lynn Barnes, Tr. 18:718.

[92] Tr. 18:650.

Again, Mr. Mitten argued that denial of recovery "would be a major step in the wrong direction for this Commission."[93] He went on to say:

> It would be a major and severe departure from a half century of consistently applied regulatory policy in Missouri to deny recovery of the regulatory asset at issue here based on the record in this case. Such a departure I'm afraid would brand Missouri as an outlier regulatory jurisdiction and would make it difficult if not impossible for utilities and their current and potential investors to count on receiving in this state the kind of regulatory support and protection for adverse financial effects of extraordinary events that is common elsewhere in the country and has been commonplace in this jurisdiction for 50 years.[94]

In fact, this argument is exactly backward. It is the recovery in rates of deferred fixed costs that would be "a major and severe departure from a half century of consistently applied regulatory policy in Missouri."[95] This AAO is not like any other AAO and it is not helpful to compare this AAO to other AAOs. The fact that AAOs for unexpected expenses due to extraordinary events are routinely allowed recovery is meaningless because it is not an apples-to-apples comparison. If the Commission grants the unlawful recovery of additional revenue to cover a past mismatch of revenues and expenses, Missouri certainly would be an "outlier regulatory jurisdiction,"[96] but not in the way intended by Mr. Mitten. It would be an outlier due to its violation of well-established legal principles. That is not something that would build confidence for Missouri regulation in the financial markets.

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[93] Tr. 18:651.

[94] Tr. 18:651-2.

[95] *Id.*

[96] *Id.*

Finally, expert testimony was adduced that contradicted the point that Mr. Mitten attempted to make. MIEC's expert witness Michael Gorman testified that investors view deferrals of expenses favorably, even if they are ultimately not recovered in rates.[97]

Conclusion:

Ameren Missouri obtained an AAO to defer its fixed costs that were not recovered between February 2009 and April 2010 due to damage to Noranda's New Madrid smelter caused by an ice storm. Now, Ameren Missouri seeks to recover the deferred fixed costs from ratepayers. However, the Missouri Supreme Court has held, "[p]ast expenses are used as a basis for determining what rate is reasonable to be charged in the future in order to avoid further excess profits or future losses, but under the prospective language of the statutes, §§ 393.270(3) and 393.140(5), they cannot be used to set future rates to recover for past losses due to imperfect matching of rates with expenses." Ameren Missouri is asking the Commission to do *exactly* what the Court, in the above quote, held that it cannot do. For this reason, the Commission must deny the requested recovery and exclude all of the amount deferred in Case No. EU-2012-0027 from revenue requirement in this case.

--Kevin A. Thompson

5. Storm Restoration Expense and Two-Way Storm Costs Tracker:

A. Should the Commission continue a two-way storm restoration cost tracker whereby storm-related non-labor operations and maintenance ("O&M") expenses for major storms would be

[97] Michael Gorman, Tr. 21:1204-5.

> *tracked against the base amount with expenditures below the base creating a regulatory liability and expenditures above the base creating a regulatory asset, in each case along with interest at the Company's AFUDC rate?*

Introduction:

The Commission should not continue the two-way storm tracker because AmMo has not shown any justification for it, and because this tracker could distort the appropriate economic incentive regarding preventative maintenance.

After rejecting AmMo's request for this tracker in ER-2010-0036, the Commission approved the extant storm expense tracker in the Company's most recent rate case, ER-2012-0166. In its current form, the tracker records the Company's actual non-labor storm-related O&M costs against a base amount set in rates.[98] Customers pay for any under-collections, and the Company returns any over-collection to customers.[99]

Staff recommends the Commission reject the tracker in this case for the same reasons it expressed in ER-2010-0036, and restore traditional ratemaking for this item of expense. The base rate amount should be set at $4.6 million. For significant storms, the Company may defer extraordinary costs for recovery in a future rate case through an Accounting Authority Order (AAO), as it has done successfully in the past.

Relevant Facts:

The Commission's order approving the storm tracker in ER-2012-0166

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[98] Ex. No. 205, Boateng Rebuttal, pg. 3, ll. 16-26.

[99] The amounts accrue interest at the Company's AFUDC rate.

took effect December 22, 2012.[100] Prior to that date, AmMo recovered its storm restoration expense through the traditional ratemaking method—through a set amount of expense included in calculation of the revenue requirement, along with the use of an AAO to defer and recover extraordinary storm expenses.[101] AmMo has used traditional rate recovery and the AAO to recover all its major storm recovery costs in recent years.[102] From April 1, 2007, through September 30, 2014, the Commission has allowed Ameren Missouri to recovery every single dollar expensed for storm restoration.[103] If the Commission rejects AmMo's request for a tracker, the Company testified that it will nevertheless continue to strive for prompt and professional restoration service, and that it will be no less aggressive in its storm restoration efforts.[104]

Historically, storm expense represents a very small amount of AmMo's operating budget.[105] In this case, the test year amount of $6.8 million represents approximately .0026 percent of the Company's total operating budget.[106] Even though storm expenses fluctuate from year to year, they do not represent a material amount of money for the Company.[107]

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[100] ER-2012-0166, *Report and Order*, issued December 12, 2012.

[101] Ex. 205, Boateng Rebuttal, pg. 8, lns. 1-26.

[102] *Id*.

[103] *Id.*

[104] Tr. 20:838-839.

[105] Ex. 205, Boateng Rebuttal at pg. 9.

[106] *Id.* as corrected, Tr. 848, ll. 14-25.

[107] *Id.*

The weather is unpredictable, but AmMo does have some control over its storm restoration expense.[108] Through prudent spending on distribution maintenance, a utility can improve the resiliency of its system and potentially reduce storm outages and restoration expense.[109] AmMo recovers distribution maintenance expense through the traditional method of a base amount set in rates, so the Company's shareholders retain the difference if AmMo incurs less distribution maintenance expense than the annual amount in rates.[110] AmMo's testimony on the storm tracker issue did not identify any operational efficiency or cost reduction to explain the reduction in distribution maintenance expense.[111]

Argument:

1) The Company has not shown any facts to justify a tracker, in light of the Commission's skepticism about economic incentive.

In a rate case, the utility bears the burden to prove that its request is just and reasonable.[112] In this case, AmMo must prove that a tracking mechanism is

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[108] Ex. No. 206, Boateng Surrebuttal, pp. 5-6.

[109] *Id.*

[110] Ex. 205, Boateng Rebuttal, pg. 9-10.

[111] Ex. 217, Hanneken Rebuttal, pg. 13, lns. 7-23. In response to Staff questions about the rational and details regarding the decrease in distribution maintenance expense levels, the Company responded with promotional language: "Ameren Missouri is diligently working to control costs through a variety of efforts while retaining our to tier reliability performance." In response to Staff's request for documentation regarding the new lower levels of distribution expense and the effect on customer outages, the Company stated only that "the reduction in our distribution maintenance costs are not expected to reduce our top tier reliability performance. In fact, we expect to sustain top tier to top quartile performance in reliability for the foreseeable future." These responses fail to satisfy Staff's concerns about the reductions and their potential consequences. See also Ex. No. 46 and 47, Rebuttal and Surrebuttal Testimony of David N. Wakeman.

[112] Section 393.150.2 RSMo. 2000. A preponderance of the evidence is the minimum standard of proof in civil cases. ***Jamison v. State, Dept. of Social Services, Div. of Family Services*****,** 218 S.W.3d 399, 415-416 (Mo. banc 2007).

justified, given the Commission's concerns about its potential to distort the utility's economic incentive.

In the oft-cited ***UCCM***[113] case, the Missouri Supreme Court outlined some common objections to departures from traditional ratemaking. For example, utilities may lose any incentive to keep down costs when they know those costs can be fully and automatically passed on to the consumer. Or, economic incentive may prompt the utility chose the method of operation that is cheapest to the utility, rather than the method which is cheapest overall.[114]

These kind of concerns informed this Commission's decision when it rejected AmMo's request for the storm expense tracker in ER-2010-0036.[115] The Commission reasoned that the traditional storm cost recovery method worked reasonably well for this expense, because the Company had been fully recovering its costs. No party disputed the quality and prudence of AmMo's storm-restoration service. The Commission found that traditional ratemaking provided both the proper incentive for prompt and professional service, which benefits customers, and reasonable expectations of full recovery of prudent costs, which benefits the Company. Therefore, there was no reason to implement a tracker:

> The Commission is unwilling to implement another tracker. As the Commission has previously indicated, trackers should be used sparingly because they tend to limit a utility's incentive to prudently manage its costs. If all such costs can simply be passed on to

[113] ***UCCM,*** *supra,* 585 S.W.2d 41.

[114] *Id*. at 49-50.

[115] ER-2010-0036, *Report and Order,* issued May 28, 2010, pg. 68.

> ratepayers, there is a natural incentive for the company to simply incur the cost. If the company must consider whether it will be able to recover a cost, it is more likely to think before it spends and maximize any possible cost savings.
>
> The storm cost recovery method the Commission has used in the past has worked reasonably well. [116]

This language suggests that trackers should be used cautiously, as a pragmatic response to specific circumstances evidenced in the record, and with careful attention to economic incentive. In this case, AmMo has introduced no evidence of a specific circumstance to justify the continuation of this tracker, and so the Commission should deny AmMo's request.

In fact, the evidence in this case shows no problem with traditional ratemaking. AmMo fully recovered its storm expense without a tracker. AmMo points to no case where this Commission rejected any of its applications for AAOs for storm restoration expense, or denied recovery of any amount of storm expense deferred pursuant to an AAO. There is no reason that storm restoration expense needs a tracking mechanism.

2) This tracker could distort economic incentives

When the Commission approved AmMo's storm expense tracker in ER-2012-0166, it did so with explicit skepticism about a tracker's potential to distort economic incentive:

> In general, the Commission remains skeptical of proposed tracking mechanisms. There is a legitimate concern that a tracker can reduce a company's incentive to aggressively control costs. However, that concern is reduced for major storm restoration costs. When faced with a massive power outage, the company's first

[116] *Id.*

> priority must be to quickly restore electric service to its customers.[117]

Staff notes the Commission's language that its concern about economic incentive "is reduced for major storm restoration" because "when faced with a massive power outage, the company's first priority must be to quickly restore electric service to its customers." Indeed, as noted at the hearing, the economic incentive to restore service and resume selling electricity drives AmMo to act promptly after a massive power outage in the wake of a storm.[118]

Staff's testimony in this case does not allege that AmMo has acted imprudently in responding to storm outages. Staff agrees with testimony in this case that AmMo should act prudently and professionally to restore service after a storm, regardless of the rate mechanism. Staff's testimony makes a different point.

Staff's evidence relates to AmMo's incentive to reduce storm expense *before* a storm occurs, not after. Staff's testimony shows that, since employing the tracker, AmMo has steadily decreased spending on maintenance for its distribution system—spending that may mitigate storm expense *before* a storm hits.[119] Staff's testimony suggests that this tracker creates an economic incentive to reduce distribution maintenance expense, because it is cheaper for the utility's shareholders to incur the expense *after* a storm causes the damage

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[117] ER-2012-0166, *Report and Order*, Issued Dec. 12, 2012, pg. 96.
[118] Tr. 20:818.

[119] Ex. 205, Boateng Rebuttal, pgs 9-10.

(because it is tracked and fully recovered from customers, with no shareholder responsibility) than it is before a storm hits.

In other words, Staff's testimony is (1) In theory, a tracker reduces the utility's economic incentive to spend money on preventative maintenance, and (2) the evidence *actually shows reduced spending* on preventative maintenance. Although Staff sought an explanation in discovery[120] and presented this evidence in rebuttal testimony,[121] AmMo's operational expert David Wakeman did not present any evidence of any new efficiency or cost reduction, or any other operational reason for the reduced spending.[122]

Conclusion:

In light of an expense tracker's potential to distort the economic incentives inherent in traditional ratemaking, the Commission should approve AmMo's requested storm tracker only if the Company shows some specific reason why traditional ratemaking is not appropriate. AmMo has not done so. Conversely, Staff has shown that AmMo's normal level of storm expense is a miniscule amount of the Company's overall revenue, and that the combination of traditional ratemaking and AAOs have allowed AmMo to recover all its storm expense in recent years, even without a tracking mechanism. Staff's evidence also suggests that the tracking mechanism may be distorting AmMo's incentives regarding distribution maintenance expense. Finally, AmMo testifies that customer service will not suffer if the Commission rejects the tracker in this case.

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[120] Ex. 217, Hanneken Rebuttal, pg. 13, lns. 7-23.

[121] Ex. 205, Boateng Rebuttal, pgs. 9-10.

[122] Ex. 47, Wakeman Surrebuttal, pgs. 2-5; Tr. 20:838-847.

B. If the storm cost tracker is not continued, what annualized level of major storm costs should the Commission approve in this case?

Staff agrees that a normalized level of approximately $4.6 million, based upon a 5-year average from January 1, 2010, through December 31, 2014, should be included in customer rates for storm restoration costs.

C. Should an amount of major storm cost over-recovery by Ameren Missouri be included in Ameren Missouri's revenue requirement and, if so, over what period should it be amortized?

Yes, and it should be amortized over five years and be included in the Company's revenue requirement.

--*John D. Borgmeyer.*

6. Vegetation Management and Infrastructure Inspection Trackers:

A. Should the vegetation management and infrastructure inspection trackers be continued?

Staff recommends that the Commission discontinue the vegetation management and infrastructure inspection tracker. Staff's recommendation is to discontinue the tracker because the reasons for originally approving the tracker no longer exist and the Commission stated a clear intent in the last Ameren Missouri rate case that this tracker should be discontinued in this case. This tracker was approved by the Commission in Ameren Missouri's 2008 rate case to capture the then-unknown costs to the utility of complying with the Commission's newly promulgated rules on vegetation management and infrastructure inspection, which were intended to increase reliability after Ameren Missouri's failure to properly maintain its system.[123] Now, over six years

[123] Hanneken Rebuttal, p. 8, ll. 13-16.

later, Ameren Missouri has completed the first cycle under the rules and there is now sufficient historical data on the cost of complying with these Commission rules so a tracker is no longer need.[124]

Ameren Missouri's witness has argued that the Company's costs to comply with these rules are still unknown, but looking at the historical data shows that, while the costs related to vegetation management and infrastructure inspections have fluctuated from year to year, as is common with many costs, overall they have remained stable.[125] While these costs may continue to experience minor fluctuations, these types of operational cost fluctuations occur with many of Ameren Missouri's expenses and are reviewed by the Company and Staff in every rate case and adjusted if necessary.[126] Ameren Missouri's witness also argued that the tracker should be continued because the costs are not discretionary as they are required by Commission rule; however, many of Ameren Missouri's costs are mandated by federal or State laws, rules, or regulations and yet the majority of these none discretionary costs are not tracked.[127] Staff is merely recommending that the Commission treat these costs as established and give them the same treatment as the Commission gives all other established costs.[128]

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[124] Hanneken Rebuttal, p. 9, ll. 6-8.

[125] Hanneken Rebuttal, p. 8, ll. 18-20.

[126] Hanneken Surrebuttal, p. 11, ll. 2-4.

[127] Hanneken Surrebuttal, p. 11, ll. 10-12.

[128] Hanneken Surrebuttal, p. 11, ll. 4 & 5.

Ameren Missouri's witness has stated that there is no downside to the continuance of this tracker, but that is simply not the case. In Ameren Missouri's last rate case the Commission stated, "In general, the Commission remains skeptical of proposed tracking mechanisms. There is a legitimate concern that a tracker can reduce a company's incentive to aggressively control costs."[129] The Commission went on to state, "[a]lthough Ameren Missouri now has more experience in complying with the rules, it still has not completed a single cycle of inspections for its rural circuits. The Commission finds that because of that remaining uncertainty the tracker is still needed. However, as the Commission has indicated in previous rate cases, it does not intend for this tracker to become permanent. ***For this case***, the Commission will renew the existing vegetation management and infrastructure inspection tracker."[130] ***[emphasis added].***

Because there is now sufficient historical data to determine a reasonable amount of expense for vegetation management and infrastructure inspection to be included in Ameren Missouri's revenue requirement and that data shows that there is no significant fluctuation in those costs, there is no legitimate reason for the continuance of this tracker. For these reasons, Staff recommends the Commission discontinue the vegetation management and infrastructure inspection tracker.

B. What amount of money should be included in the revenue requirement for Vegetation Management and Infrastructure Inspection?

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[129] ER-2012-0166, *Report and Order,* p. 96.

[130] *Id.,* at 106 & 107 (emphasis added).

Staff recommends using a three-year average for both the vegetation management and infrastructure inspection expense to calculate the amount of expense to be included in the revenue requirement.[131] Staff's three-year average for vegetation management is approximately $54.5 million and Staff's three-year average for infrastructure inspection is approximately $5.8 million.[132] Staff recommends a three-year average level of expense for calculating the base level amount of vegetation management and infrastructure inspection expense to be included in Ameren Missouri's revenue requirement because, based off the historical data, a three-year average is the most reasonable estimate of future expense. A three-year average is the most reasonable estimate of the Company's future expenses because while there are minor fluctuations in costs from year-to-year, looking at the entire body of data, which encompasses approximately six years, the costs have stabilized over the past three years.[133]

Ameren Missouri has argued that the Commission should allow the Company to use only test-year actual amounts trued-up through December 31 for calculating the level of expense to be included in the revenue requirement.[134] The difference in Staff and the Company's recommendations amounts to $2.1 million.[135] While this has been the method for setting the level of expense for these items in Ameren Missouri's rate cases since 2008, that methodology

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[131] Hanneken Surrebuttal, p. 9, ll. 2-5.

[132] *Id*., at ll.10-12.

[133] Lisa Hanneken, Tr. 20:930 & 931.

[134] Moore at p. 31.

[135] Laura Moore, Tr. 20:923, ll. 7-11.

was based on the premise that the tracker would continue. If the Commission discontinues the vegetation management and infrastructure tracker as Staff, OPC, and MIEC have all recommended, then using a three-year average level of expense for these items is the most reasonable method of calculating the amount to be included in Ameren Missouri's revenue requirement.

C. Should an amount for cost over-recovery be included in Ameren Missouri's revenue requirement and, if so, over what period of time should they be amortized?

Staff agrees with Ameren Missouri that an amount for cost over-recovery should be included in Ameren Missouri's revenue requirement. Staff recommends a net amortization amount of approximately $1.5 million to be amortized over three years.[136] Staff's net level of amortization expense for vegetation management and infrastructure inspection addresses both the over-recovery and under-recovery of the prior amortization level, as well as the tracked amounts since Ameren Missouri's last rate case. Ameren Missouri has indicated that it agrees with Staff's recommended net level of amortization expense and Staff's recommended time period for the amortization.

--Alexander Antal.

7. Union Proposals:

A. Can the Commission mandate or require that the Company address its workforce needs in a particular manner and, if so, should it do so?

B. Should the Commission require the additional reporting requested by Mr. Walters?

[136] Hanneken Surrebuttal, p. 10, ll. 7 & 8.

Staff has no position on the issues raised by the Union.

8. Return on Equity ("ROE")

In consideration of all relevant factors, what is the appropriate value for Return on Equity ("ROE") that the Commission should use in setting Ameren Missouri's Rate of Return?

Introduction:

Staff recommends that the Commission allow Ameren Missouri a Return on Equity ("ROE") in the range 9.00% to 9.50%, midpoint 9.25%, based upon its expert analysis of market-driven data using traditional analytical tools.[137] This ROE should be combined with Ameren Missouri's December 31, 2014, capital structure, cost of debt and cost of preferred stock to arrive at the allowed rate of return ("ROR") in this case of 7.33% to 7.58%, midpoint 7.45%.[138]

Party & Expert	Recommendation
AmMo (Robert Hevert)[139]	10.20%-10.60%, **10.40%**
Wal-Mart (Steve Chriss)[140]	**9.8**
MIEC (Michael Gorman)[141]	9.00%-9.60%, **9.30%**
Staff (David Murray)[142]	9.00%-9.50%, **9.25%**
OPC (Lance Schafer)[143]	8.74%-9.22%, **9.01%**
TABLE 1 – EXPERT RECOMMENDATIONS.	

[137] *Staff's RR Report,* p. 10.

[138] Based on true-up information received from Ameren Missouri, its capital structure as of December 31, 2014, consisted of 51.76% common stock equity, 1.07% preferred stock and 47.18% long-term debt. Its cost of preferred stock was 4.180% and its cost of long-term debt was 5.559%. Murray Surrebuttal, p. 4.

[139] Hevert Direct, p. 2; Hevert Rebuttal, pp. 124-5; Hevert Surrebuttal, p. 2.

[140] Chriss Revenue Requirement Direct, p. 13.

[141] Gorman Direct, p. 2.

[142] *Staff's RR Report,* p. 10.

[143] Schafer Direct, p. 3.

The recommendations before the Commission in this case range between 8.74% and 10.60%. Three of the expert witnesses testified that an authorized ROE anywhere within his recommended range would be appropriate.

What is the Significance of This Issue?

Cost of capital is the largest single issue in this case – the difference between Staff's position and the Company's is worth over $67 million.[144] Cost of capital is always a large issue in terms of the amount of revenue requirement and also a contentious issue in a general rate case; this case is no exception. The term "cost of capital" refers to the cost of each component of the capital structure, typically long-term debt, preferred equity and common equity.[145] The cost of both long-term debt and preferred equity is historic or "embedded" and can be readily determined from the controlling instruments.[146] The cost of common equity, on the other hand, is driven by the market and must be estimated through expert analysis and judgment.

The Experts

Four expert financial analysts testified before the Commission in this case and offered estimates to the Commission for the cost of common equity. Mr. Hevert, Mr. Gorman and Mr. Murray all have MBAs and hold the Chartered Financial Analyst ("CFA") designation.[147] "The CFA designation is one of the

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[144] *Staff's True-up Reconciliation.*

[145] Short-term debt, that is, debt payable in less than one year, is typically excluded.

[146] For example, the interest rate on a corporate bond can be determined by examining the indenture.

[147] Hevert Direct, p. 1; Gorman Direct, pp. 1 and 4; *Staff RR Report,* App. 1 at p. 61; Schafer Direct, pp. 1-2.

most respected designations in finance and is considered by many to be the gold standard in the field of investment analysis."[148] Each of them has testified before the Commission concerning ROE many times.[149] Mr. Murray is also a Certified Rate of Return Analyst ("CRRA").[150] Mr. Hevert and Mr. Gorman are independent consultants. Mr. Hevert provides ROE testimony solely on behalf of utilities.[151] He charges $350 per hour.[152] Mr. Gorman provides ROE testimony primarily on behalf of industrial consumers and federal executive agencies.[153] He charges $235 per hour.[154] Mr. Schafer, OPC's expert witness, is an employee of OPC.[155] He has an MBA with a specialization in Finance and has passed the first of three examinations for the CFA designation.[156] This was Mr. Schafer's first experience as an expert witness.[157] Mr. Chriss is an employee of Wal-Mart, on whose behalf he testified.[158] He has a Master of Science degree in Agricultural Economics and several years of experience as a utility regulatory analyst.[159] Mr. Chriss did not independently perform a financial analysis, but he

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[148] Schafer Direct, p. 2.

[149] The case participation experience of these witnesses is detailed at Hevert Direct, Attachment A; Gorman Direct, p. 3; and *Staff RR Report,* App. 1, pp. 61-67.

[150] *Staff RR Report,* App. 1 at p. 61.

[151] Robert Hevert, Tr. 21:1144.

[152] *Id.*

[153] Michael Gorman, Tr. 21:1211, 1271.

[154] *Id.,* at 1271.

[155] Schafer Direct, pp. 1-2.

[156] *Id.*

[157] *Id.*

[158] Chriss Revenue Requirement Direct, p. 1. His title is Senior Manager, Energy Regulatory Analysis.

[159] *Id.*

did sponsor an ROE recommendation.[160]

What is the Rate of Return?

In addition to the Company's prudent operating and maintenance expenses, revenue requirement includes both a return "of" and a return "on" the net current value of the shareholders' investment.[161] The former is provided by depreciation expense; the latter by the rate of return. The rate of return is a multiplier which, applied to the net current rate base, results in the return or "profit" allowed to the investors in return for the use of their private property in serving the public.[162] The Due Process Clause requires that the shareholders be allowed an opportunity to earn a reasonable return on their investment.[163] Pursuant to financial theory, a fair rate of return is an amount sufficient to meet the utility's capital costs.[164] For this reason, the rate of return is considered to be equivalent to the Weighted Average Cost of Capital ("WACC").[165] The WACC is computed by multiplying a ratio reflecting the proportion that each capital component constitutes of the whole by its cost and summing the results.[166] The Commission does not set the rate of return directly, but sets the ROE which is a

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[160] *Id.,* pp. 8-13.

[161] Edison Electric Institute (EEI), ***Rate Shock Mitigation*** (June, 2007; available on the Internet) p. 5 ("In simple terms, a utility's cost of service or revenue requirement consists of three primary elements: (1) operating costs, such as fuel costs, purchased power costs, operations and maintenance (O&M) costs and customer service costs; (2) a return of capital cost, otherwise known as depreciation expense; and (3) a return on capital cost, including applicable income taxes.").

[162] *Staff RR Report,* p. 10.

[163] ***UCCM,*** *supra,* 585 S.W.2d at 49.

[164] *Staff RR Report,* p. 13.

[165] *Staff RR Report,* p. 10.

[166] *Id.*

component of the rate of return. In this way, the Commission indirectly sets the rate of return.

Determination of the Cost of Common Equity:

The cost of common equity capital must be estimated. This is a difficult task, as academic commentators have recognized.[167] There are negative consequences if ROE is set either too low or too high.[168] It is said that this "is an area of ratemaking in which agencies welcome expert testimony and yet must often make difficult choices between conflicting testimony."[169] The evaluation of expert testimony is left to the Commission, which “may adopt or reject any or all of any witness’s [sic] testimony.”[170]

<u>Cost of Equity (“COE”) v. Return on Equity (“ROE”)</u>

A matter of terminology arises at the outset. Staff maintains that the cost of equity ("COE") is distinct from the return on equity ("ROE").[171] Nonetheless, the truth of Staff's position is readily apparent. The COE is the return necessary to induce investors to invest in the utility's common stock; it is a market-driven

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[167] C.F. Phillips, Jr., ***The Regulation of Public Utilities: Theory & Practice*** 394 (PUR: Arlington, VA, 1993); L.S. Goodman, 1 ***The Process of Ratemaking***, 606 (PUR: Vienna, VA, 1998).

[168] Michael Gorman, Tr. 21:1216.

[169] Goodman, *supra,* 606.

[170] ***State ex rel. GS Technologies Operating Company, Inc. v. Public Service Commission of Missouri,*** 116 S.W.3d 680, 690 (Mo. App., W.D. 2003); ***State ex rel. Associated Natural Gas Company v. Public Service Commission,*** 37 S.W.3d 287, 294 (Mo. App., W.D. 2000) (quoting ***State ex rel. Associated Natural Gas Company v. Public Service Commission,*** 706 S.W.2d 870, 880 (Mo. App., W.D. 1985)).

[171] *Staff RR Report,* p. 10 n. 7; Murray Rebuttal, p. 2; Tr. 21:1362-3, 1369. This view is not shared by Mr. Hevert, *e.g.,* “Throughout my Direct Testimony, I interchangeably use the terms “ROE” and “Cost of Equity.”; Hevert Direct, p. 2 n. 1.

value that must be discerned by the experts through analysis and judgment.[172] The ROE, on the other hand, is the figure set by the Commission.[173] The ROE has often been referred to in this case as the "allowed ROE" or "authorized ROE" in contradistinction to the COE, which is determined by the market and the "earned ROE," which is a measure of the utility's actual financial performance over some past period of time. The COE and the authorized ROE may be the same number, but they don't have to be. It is Staff's view that the allowed ROE is uniformly set above COE by regulatory commissions across the nation, the spread generally being between 250 and 300 basis points.[174] Staff's expert witness, David Murray, testified that Ameren Missouri's actual COE is in the six to eight percent range, but that investors expect the Commission to set its ROE at 9.5 percent, if not lower.[175]

<u>Constitutional Parameters</u>

The United States Supreme Court, in two frequently-cited decisions, has established the constitutional parameters that must be met in setting the cost of common equity.[176] Each of the experts has affirmed that he conducted his studies and made his recommendations with these parameters in mind.[177] In the

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[172] *Staff RR Report,* p. 10 n. 7; David Murray, Tr. 21:1344-5; Hevert Direct, p. ii; Gorman Direct, p. 11.

[173] *Staff RR Report,* p. 10 n. 7.

[174] David Murray, Tr. 21:1356, 1362-3.

[175] David Murray, Tr. 21:1348, 1356-7, 1359.

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

[177] Hevert Direct, pp. 5-6; *Staff RR Report,* pp. 11-13; Gorman Direct, p. 12; Schafer Direct, pp. 5-6.

earlier of these two cases, ***Bluefield Water Works***, the Court stated that:

> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the services are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.[178]

In the same case, the Court provided the following guidance as to the return due to equity owners:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[179]

The Court restated these principles in ***Hope Natural Gas Company***, the later of the two cases:

> '[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

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[178] ***Bluefield***, *supra,* 262 U.S. at 690, 43 S.Ct. at 678, 67 L.Ed. at 1181.

[179] *Id.,* 262 U.S. at 692-93, 43 S.Ct. at 679, 67 L.Ed. at 1182-1183.

> sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[180]

From these two decisions, three guiding principles can be discerned:

(1) An adequate return is commensurate to the returns realized from other businesses with similar risks. This is the principle of the commensurate return.

(2) An adequate return is sufficient to assure confidence in the financial integrity of the utility and to maintain the utility's credit rating. This is the principle of financial integrity.

(3) An adequate return is sufficient to enable the utility to obtain necessary capital. This is the principle of capital attraction.

The first of these principles is based on risk and unmistakably requires a comparative process. The return on common equity set by the PSC must be about as much as investors would realize from other investments with similar risks.[181] What entities are those? Other public utilities. Financial analysts and investors recognize that every line of business is, by its very nature, subject to a set of unique risks. Consequently, the business entities that face corresponding risks and uncertainties to the utility under consideration are necessarily other utilities engaged in delivering the same service under similar conditions. Therefore, the Commission must look to the returns required from a proxy group

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[180] ***Hope***, *supra,* 320 U.S. at 603, 64 S.Ct. 288, 88 L.Ed. 345 (citations omitted).

[181] ***Hope***, *supra,* 320 U.S. at 603, 64 S.Ct. 288, 88 L.Ed. 345 (citations omitted): "By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."

of comparable companies in setting the utility's return on common equity.[182]

The second principle, simply stated, refers to the effect of the PSC's decision on the utility's credit rating. If the Commission's decision will not cause it to drop, then the utility's credit is maintained and confidence that the utility will continue in business in the future, meeting its obligations as they come due, providing safe and adequate service to its customers, and yielding a fair return to its shareholders is unimpaired.

The third principle refers to the utility's ability to compete in the market place for necessary capital. Ameren Missouri competes for capital with other utilities and utilities likewise compete with unregulated businesses.[183]

Each of the experts testified that an authorized ROE within his recommended range would meet the constitutional criteria.[184]

Proxy Groups

Because the constitution requires a comparative analysis, each of the experts applied well-established financial analytical methods to one or more

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[182] Hevert Direct, p. 8: "Since the ROE is a market-based concept, and Ameren Missouri is not a publicly traded entity, it is necessary to establish a group of comparable publicly-traded companies to serve as its "proxy". Even if Ameren Missouri were a publicly traded entity, short-term events could bias its market value during a given period of time. A significant benefit of using a proxy group is that it serves to moderate the effects of anomalous, temporary events associated with any one company." *Staff RR Report:* "Financial theory holds that the company-specific Discounted Cash Flow ("DCF") method satisfies the constitutional principles inherent in estimating a return consistent with those of companies of comparable risk; 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 Ameren Missouri." *See* Schafer Direct, p. 7.

[183] Tr. 26:1711-1712, 1759 (Gorman).

[184] Robert Hevert, Tr. 21:1124-27; Michael Gorman, Tr. 21:1197-8; David Murray, Tr. 21:1340-41.

proxy groups. The goal in constructing these proxy groups is to approximate the profile of Ameren Missouri as closely as possible.[185] This is achieved by using comparable companies that are in the same line of business as Ameren Missouri and which are perceived by investors as having the same degree of risk. The various proxy groups are set out comparatively in Table 2.

Robert Hevert formed a proxy group of 16 companies using the following criteria:[186]

- All Value Line electric utilities;
- Excluding companies that do not consistently pay quarterly cash dividends;
- Covered by at least two utility industry equity analysts;
- With investment grade senior unsecured bond and/or corporate credit ratings from S&P;
- Whose regulated operating income over the three most recently reported fiscal years comprised at least 60.00 percent of the respective totals for that company;
- Whose regulated electric operating income over the three most recently reported fiscal years represented less than 90.00 percent of total regulated operating income; and
- Excluding companies that are currently known to be party to a merger, or other significant transaction.

Mr. Hevert updated his analyses in his rebuttal testimony using a "Combined Proxy Group" which consisted of his original proxy group plus Mr. Murray's.[187]

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[185] Robert Hevert, Tr. 21:1145. *Staff RR Report,* p. 27: "Although Staff has changed its proxy group selection process as compared to the 2012 rate cases, the ultimate goal is the same, which 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."

[186] Hevert Direct, pp. 9-10.

Staff utilized two proxy groups. One was constructed for this case using criteria somewhat similar to Mr. Hevert's criteria with the major difference being that Staff's criteria required its companies to have at least 80% of assets and 80% of net income from regulated utility operations, whereas Mr. Hevert only required 60% of net income be derived from regulated utility operations. Staff further refined its proxy group to exclude companies that had material volatility in net income caused by its non-regulated utility operations; and the other was Staff's proxy group in Case No. ER-2012-0166, updated by excluding two companies due to merger activity .[188]

Mr. Gorman simply used Mr. Hevert's proxy group, but adjusted it by excluding Duke Energy and Cleco because of merger activity.[189]

Mr. Schafer constructed a proxy group of 10 companies, again, using generally similar criteria.[190]

Hevert & Gorman	**Murray**	**Schafer**
AEP	AEP	AEP
Cleco	-	-
Duke Energy	-	-
Empire	-	-
Great Plains	Great Plains	Great Plains
Hawaiian Electric	-	-
IDACORP	-	IDACORP
NextEra Energy	-	-
Northeast Utilities	-	-
Otter Tail	-	-
Pinnacle West	Pinnacle West	Pinnacle West

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[187] Hevert Rebuttal, p. 26.

[188] *Staff RR Report,* p. 27. Cleco Corporation and Wisconsin Energy Resources were excluded.

[189] Gorman Direct, p. 13.

[190] Schafer Direct, pp. 7-9.

Hevert & Gorman	Murray	Schafer
PNM Resources	PNM Resources	PNM Resources
Portland General	Portland General	Portland General
Southern	Southern	Southern
Westar Energy	Westar Energy	Westar Energy
-	Alliant	Alliant
-	Ameren	-
-	CMS Energy	-
-	DTE Energy	-
-	**OGE Energy**	-
-	**TECO Energy**	-
-	Xcel Energy	Xcel Energy

TABLE 2 – COMPARATIVE PROXY GROUPS.
Excluded by Mr. Gorman.
Eliminated for purposes of Staff's refined group.

Analytical Methods:

> [A]ll models used to estimate the Cost of Equity are subject to limiting assumptions or other methodological constraints. Strict adherence to any single approach, or the results of any single approach, can result in misleading conclusions. A reasonable ROE estimate therefore considers capital market conditions and weighs the individual and collective results of alternate methodologies.[191]

Two principal methods have emerged for determining the cost of common equity, the "market-determined" approach and the "comparable earnings" approach.[192] The market-determined approach relies upon stock market transactions and estimates of investor expectations.[193] Examples of market-determined methods are the Discounted Cash Flow method ("DCF"), the Capital Asset Pricing Model ("CAPM") and the Risk Premium method.[194] The comparative earnings approach is a comparative method and relies upon the

[191] Hevert Rebuttal, p. 14.

[192] Phillips, *supra,* 394.

[193] *Id.*

[194] *Id.*

concept of "opportunity cost," that is, the return the investment would have earned in the next best alternative use.[195] None of the analysts in this case used the comparative earnings approach.

In the final analysis, the method employed to estimate the cost of common equity is unimportant, as long as the result that is reached satisfies the constitutional requirements.[196] "If the total effect of the rate order cannot be said to be unjust or unreasonable, judicial inquiry is at an end."[197] "It is the impact of the rate order which counts; the methodology is not significant."[198] Within a wide range of discretion, the Commission may select the methodology used in ratemaking, including fixing the ROE.[199] The Commission may select its methodology in determining rates and make pragmatic adjustments called for by particular circumstances.[200] It may employ a combination of methodologies and vary its approach from case-to-case and from company-to-company.[201] "No methodology being statutorily prescribed, and ratemaking being an inexact

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[195] *Id.,* at 397.

[196] ***State ex rel. Arkansas Power & Light Company v. Missouri Public Service Commission,*** 736 S.W.2d 457, 462 (Mo. App., W.D. 1987); ***State ex rel. Associated Natural Gas Company v. Public Service Commission of Missouri,*** 706 S.W.2d 870, 879 (Mo. App., W.D. 1985).

[197] ***Hope***, *supra,* 320 U.S. at 602, 64 S.Ct. at 287, 88 L.Ed. 345 at ___ .

[198] ***State ex rel. GTE North, Inc. v. Public Serv. Commission,*** 835 S.W.2d 356, 361, 371 (Mo. App., W.D. 1992).

[199] ***Missouri Gas Energy v. Public Service Commission***, 978 S.W.2d 434 (Mo. App., W.D. 1998), *rehearing and/or transfer denied*; ***State ex rel. Associated Natural Gas Company v. Public Service Commission***, 706 S.W.2d 870, 880, 882 (Mo. App., W.D. 1985); ***State ex rel. Missouri Public Service Company v. Fraas***, 627 S.W.2d 882, 888 (Mo. App., W.D. 1981).

[200] ***State ex rel. Associated Natural Gas Company v. Public Service Commission of Missouri,*** 706 S.W.2d 870, 880 (Mo. App., W.D. 1985).

[201] ***State ex rel. City of Lake Lotawana v. Public Service Commission***, 732 S.W.2d 191, 194 (Mo. App., W.D. 1987).

science, requiring use of different formulas, the Commission may use different approaches in different cases."[202] The Constitution "does not bind ratemaking bodies to the service of any single formula or combination of formulas."[203]

The analysts all used variants of the same analytical methods, relying on market-based data to quantify investor expectations regarding required equity returns. However, while the methods were similar, the data inputs were different, leading to significantly different results between Mr. Hevert, on the one hand, and Mr. Murray, Mr. Gorman and Mr. Schafer of the other.[204] Each analyst used variations of the DCF method and the CAPM. Only Mr. Schafer did not also use a version of the Risk Premium method.

- **Discounted Cash Flow ("DCF") method:** The DCF method is based on the theory that a stock's current price reflects the present value of all expected future cash flows.[205] In its simplest, "constant growth" form, the DCF is simply the sum of the dividend yield (current dividend/current stock price) and a growth rate.[206] The dividend yield is calculated by dividing the annualized dividend by the current stock price. The selection of a growth rate is critical. The Constant Growth DCF assumes stable growth into

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[202] ***Arkansas Power & Light,*** *supra,* 736 S.W.2d at 462.

[203] ***Federal Power Commission v. Natural Gas Pipeline Company***, 315 U.S. 575, 586, *62 S.Ct. 736, 743, 86 L.Ed. 1037, 1049-50* (1942); *see* ***State ex rel. Associated Natural Gas Company v. Public Service Commission of Missouri,*** 706 S.W.2d 870, 880 (Mo. App., W.D. 1985).

[204] Michael Gorman, Tr. 21:1197.

[205] Hevert Direct, p. 14.

[206] *Staff RR Report,* p. 39.

perpetuity.[207] Because of the limitations inherent in that assumption,[208] each analyst also performed a Multi-Stage DCF, in which a different growth rate is specified for each of several stages.[209] "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."[210] The terminal stage growth rate is typically not higher than projected GDP[211] and may be as low as the inflation rate.[212] The choice of the terminal stage growth rate is critical.[213]

- **Capital Asset Pricing Model ("CAPM"): "**The CAPM method of analysis is based upon the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk

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[207] Hevert Direct, p. 14; *Staff RR Report,* p. 30.

[208] Gorman Direct, pp. 20-21:"The limitation on the constant growth DCF model is that it cannot reflect a rational expectation that a period of high/low short-term growth can be followed by a change in growth to a rate that is more reflective of long-term sustainable growth."

[209] *Id.,* p. 19; Ex. 245 (Missing pages from *Staff's RR Report*).

[210] Ex. 245.

[211] Gorman Direct, p. 22 "Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services. Utilities' earnings/dividend growth is created by increased utility investment or rate base. Such investment, in turn, is driven by service area economic growth and demand for utility service. In other words, utilities invest in plant to meet sales demand growth, and sales growth, in turn, is tied to economic growth in their service areas." *See also* Gorman Direct, pp. 23-5.

[212] Ex. 245: "[I]n Staff's experience, most DCF analyses do not assume a growth rate much higher than the expected rate of inflation, currently 2.0% to 2.5%."

[213] *Staff RR Report,* p. 34.

premium associated with the specific security."[214] It is a type of risk premium analysis.[215] The CAPM's inputs are the risk-free rate, the market-risk premium, and beta, a coefficient unique to each company that expresses its risk compared to that of the market as a whole.[216] Because utilities are less risky than the market as a whole, the beta values used by the analysts are less than 1.00.[217]

- **Risk Premium method:** "This model is based on the principle that investors require a higher return to assume greater risk."[218] The inputs are a debt yield and the equity risk premium.[219]

Analytical Results

The inputs used by the four experts that actually performed analyses, and the results that they obtained, are set out below in Table 5. Table 3, immediately below, sets out their recommendations. Table 4 presents a graphic comparison of those recommendations.

Expert	**Recommendation**
Robert Hevert	10.20%-10.60%, **10.40%**
Michael Gorman	9.00%-9.60%, **9.30%**
David Murray	9.00%-9.50%, **9.25%**
Lance Schafer	8.74%-9.22%, **9.01%**

TABLE 3 -- RECOMMENDATIONS

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[214] Gorman Direct, p. 32.

[215] Hevert Direct, p. 24.

[216] Gorman Direct, p. 33; Hevert Rebuttal, p. 117.

[217] Hevert Rebuttal, p. 117.

[218] *Id.,* p. 27; Hevert Direct, p. 28.

[219] Hevert Direct, p. 28.

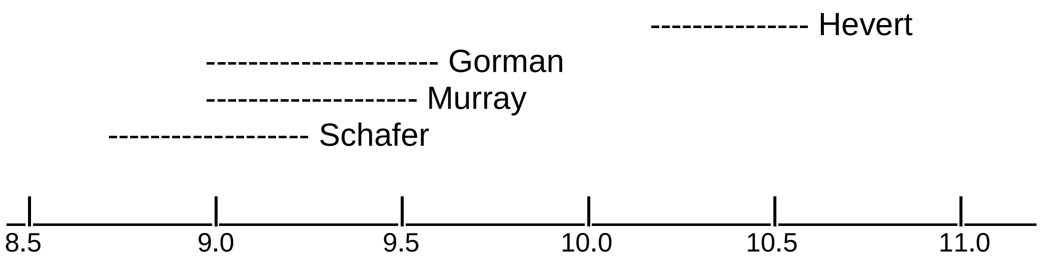

TABLE 4 – COMPARISON OF RECOMMENDATIONS

<u>Parsing the Experts</u>

A glance at Table 4 shows that the recommendations of Mr. Murray, Mr. Gorman and Mr. Schafer are clustered together at the lower end of the scale; the area of overlap extends from 9.0% to 9.22%. One immediate and obvious conclusion is that the weight of expert opinion favors an allowed ROE at or below 9.5%.

Each of the experts criticized the methods, inputs and results of the others. Mr. Hevert criticized the results obtained by the other experts as too low; they criticized his results as too high. Messrs. Murray, Gorman and Schafer level most of their criticisms at Mr. Hevert, implying that he purposely manipulated his analyses to obtain high results. Mr. Murray stated:

> Mr. Hevert's constant growth DCF cost of equity estimate makes the incorrect assumption that investors believe utilities' dividends per share ("DPS") will grow at the same rate as a projected 5-year compound annual growth rate ("CAGR") in EPS into perpetuity. Mr. Hevert's multi-stage DCF methodology makes the incorrect assumption that utilities' DPS can grow at an inflated estimate of GDP into perpetuity. Mr. Hevert's cost of equity estimates using the CAPM are much higher than one would expect in the current capital market environment. Mr. Hevert's high results are driven by two factors: (1) his projected total returns for the S&P 500 are double those of reputable investors and professional forecasts, and (2) he adds the risk premium resulting from these irrational

ANALYTICAL METHODS, CRITICAL INPUTS AND RESULTS		
Method	**Inputs**	**Results**
HEVERT		
Constant Growth DCFs	Growth Rate: 5.54%, 5.68%	Combined Grp: 8.47, 9.58, 10.52 Revised Grp: 8.40, 9.48, 10.46
Multi-stage DCFs	Stage 1: 5.54%, 5.68% Stage 3: 5.63%	Combined Grp: 9.51, 9.92, 10.24 Revised Grp: 9.56, 9.98, 10.31
CAPMs	Risk-free Rate: 3.04, 3.68 Beta: 0.757, 0.760, 0.758, 0.750 Market Risk Premium: 9.72, 10.45	Combined Grp: 10.39-11.62 Revised Grp: 10.33-11.60
Bond Yield Plus Risk Premium	Risk-free Rate: 3.04, 3.68, 5.45 Risk Premium: 7.06, 6.52, 5.41	10.10%, 10.20%, 10.86%
MURRAY		
Constant Growth DCF	Growth Rate: 3.5%-4.5%	7.4%-8.4%
Multi-stage DCF	Stage 1: 5.73% Stage 3: 3.00%-4.00% Stage 3:* 4.40% *Nominal GDP Growth Rate.	Broad Grp: 7.65, 8.03, 8.41 Refined Grp: 7.60, 7.98, 8.37 GDP 4.40%: 8.67%, 8.72%
CAPM	Risk-free Rate: 3.17% Beta: 0.73, 0.74 Market Risk Premium: 6.2, 4.64	Arithmetic: 7.66%, 7.76% Geometric: 6.53%, 6.60%
Rule of Thumb	Risk Premium: 3.0%-4.0% Bonds: 4.13%, 4.76%	7.13%-7.76% 8.13%-8.76%
GORMAN		
Constant Growth DCF	Growth Rate: 5.05%	8.87%-8.95%
Sustainable Growth DCF	Growth Rate: 4.77%	8.24%-8.71%
Multi-stage DCF	Stage 1: 5.05% Stage 3: 4.60%	8.54%-8.57%
Bond Yield Plus Risk Premium	Risk-free Rate: 4.10, 4.71 Risk Premium: 4.41, 6.28 Risk Premium: 3.03, 5.03	8.51%-10.38%, 9.91% 7.74%-9.74%, 9.24%
CAPM	Risk-free Rate: 4.10% Beta: 0.76 Market Risk Premium: 6.2, 7.3	8.82%-9.66%, 9.24%
SCHAFER		
Constant Growth DCF	Growth Rate: 5.02%	8.77% + 0.45 = 9.22%
Multi-stage DCF	Stage 1: 5.02% Stage 3: 4.86%	8.62% + 0.45 = 9.07%
CAPM	Risk-free Rate: 3.2%, 4.5% Beta: 0.77 Market Risk Premium: 5.4%	7.44% + 1.3 = 8.74%

TABLE 5.

Sources:
Hevert Direct, pp. 12-31; Rebuttal, Sch's RBH-R7 through RBH-R12; *Staff RR Report,* pp. 30-44 & App. 2; Ex. 245; Gorman Direct, pp. 15-38, Sch's MPG-3 through MPG-16; Schafer Direct, pp. 10-37, Sch's LCS-3 through LCS-10.

> projected returns to projected interest rates. The use of projected interest rates completely contradicts the efficient market hypothesis which maintains that current market prices (and their resulting yields) already reflect investors' expectations of capital market and economic changes in the future. Mr. Hevert's risk premium methodology is based on the spread of allowed ROEs as they compare to 30-year Treasury bond yields over an historical period.[220]

Similarly, Mr. Gorman stated:

> Mr. Hevert's estimated return on equity of 10.40% is overstated and should be rejected. Mr. Hevert's analyses produce excessive results for various reasons, including the following: (1) his constant growth DCF results are based on excessive, unsustainable growth rates; (2) his multi-stage DCF is based on an unrealistic Gross Domestic Product ("GDP") growth estimate and unreasonable payout ratio assumptions; (3) his CAPM is based on inflated market risk premiums; and (3) his Bond Yield Plus Risk Premium is based on inflated utility equity risk premiums.[221]

Likewise, Mr. Schafer stated:

> Mr. Hevert's results are unreasonably high because of the following factors:
>
> 1. The use of "mean high" and "mean low" growth estimates;
>
> 2. A dividend payment timing error;
>
> 3. An inappropriate payout-ratio forecast;
>
> 4. An unreasonably high estimation of GDP;
>
> 5. Risk premia established with unreasonably high constant-growth rates;
>
> 6. The selective use of a "long term projected" risk-free rate;

[220] Murray Rebuttal, p. 4.

[221] Gorman Rebuttal, p. 2.

7. An inappropriately applied argument relating to the supposed inverse relationship between interest rates and the equity risk premium.[222]

Messrs. Murray, Gorman and Schafer each testify, as the above excerpts show, that Ameren Missouri expert witness Robert Hevert manipulated his analyses in order to produce higher results. One area of concern is the growth rates used in the various DCF analyses.

	Constant Growth DCF	**Terminal Stage, Multi-Stage DCF**
HEVERT	5.54%, 5.68%[223]	5.63%[224]
MURRAY	3.5%-4.5%[225]	3.0%-4.0%[226]
GORMAN	4.77%, 5.05%[227]	4.60%[228]
SCHAFER	5.02%[229]	4.86%[230]
TABLE 6 – COMPARISON OF ANALYSTS' GROWTH RATES.		

Table 6 demonstrates that the analysts' criticisms of Mr. Hevert are correct – the highest values on the table are the growth rates Mr. Hevert used. The *lowest* growth rate used by Mr. Hevert is 83 basis points *higher* than the average of the growth rates used by the other analysts, 4.71%.[231] It is 49 basis points *higher* than the highest of the growth rates used by the other analysts, 5.05%.

[222] Schafer Rebuttal, p. 2.

[223] Hevert Rebuttal, Sch. RBH-R7.

[224] *Id.,* Sch. RBH-R8.

[225] *Staff RR Report,* p. 33.

[226] Ex. 245, p. 2.

[227] Gorman Direct, pp. 18, 20.

[228] *Id.,* p. 25.

[229] Schafer Direct, Sch. LCS-2. The ten values in column 6 were averaged.

[230] Schafer Direct, p. 26.

[231] (4.0 + 4.77 + 5.05 + 5.02) / 4 = 4.71.

The choice of growth rate is critical since the DCF result is simply the sum of the growth rate and the dividend yield. The dividend yield factor, which is calculated by dividing the current dividend by the stock price, cannot readily be manipulated by analysts. The choice of growth rate, on the other hand, is a matter of expert judgment. As Mr. Gorman testified, "Most of [Mr. Hevert's] DCF return estimates are based on growth rates that are too high to be reasonable estimates of long-term sustainable growth. Therefore, many of his constant growth DCF analyses reflecting analysts' growth are not producing reasonable DCF return estimates."[232]

The contrast between the high numbers used by Mr. Hevert and the lower numbers used by the other analysts is most striking in the third column of Table 6, the terminal growth rates used in the Multi-Stage DCF analysis. Mr. Hevert's growth rate, 5.63%, is 131 basis points *higher* than the average of the growth rates used by the other three analysts, 4.32%.[233] It is 77 basis points *higher* than the highest of their growth rates, 4.86%. Mr. Gorman explained, "Mr. Hevert's nominal GDP growth rate is based on a historical real GDP growth rate that is out of line with the consensus economists' forward-looking real GDP growth outlooks."[234]

In the Multi-Stage DCF, the terminal growth rate is the most significant of those used because it projects to perpetuity, that is, forever. Mr. Murray testified, "it is extremely important to select a reasonable growth rate for this stage to

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[232] Gorman Rebuttal, p. 4.

[233] (3.5 + 4.6 + 4.86) / 3 = 4.32.

[234] Gorman Rebuttal, p. 7.

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."[235] The weight of expert opinion suggests that this growth rate should not be higher than the growth expected in the Gross Domestic Product ("GDP"), which is "[t]he value of all finished goods and services produced within a country during a given period of time (usually measured annually) . . . [, including] public and private consumption, government expenditures, investments, and exports less imports."[236] Mr. Hevert updated his analyses in his rebuttal testimony, including using a new terminal growth rate for his Multi-Stage DCF,[237] however, he provided no explanation whatsoever for the source of this number. He explained his original terminal growth rate as follows:

> The long-term growth rate of 5.71 percent is based on the real GDP growth rate of 3.27 percent from 1929 through 2013, and an inflation rate of 2.37 percent. The GDP growth rate is calculated as the compound growth rate in the chain-weighted GDP for the period from 1929 through 2013. The rate of inflation of 2.37 percent is a compound annual forward rate starting in ten years (i.e., 2024, which is the beginning of the terminal period) and is based on the 30-day average projected inflation based on the spread between yields on long-term nominal Treasury Securities and long-term Treasury Inflation Protected Securities, known as the "TIPS spread".[238]

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[235] *Staff RR Report,* p. 34 (emphasis in the original).

[236] Hevert Direct, p. ii. *See* Gorman Direct, pp. 22-24: "the U.S. GDP nominal growth rate is a conservative proxy for the highest sustainable long-term growth rate of a utility." *Id.,* p. 22. *See* Schafer Direct, p. 22: "The third-stage growth rate is the same for all companies and is based on long-term growth in GDP, which should serve as the absolute maximum rate when establishing a long-term growth rate." *See* Hevert Direct, pp. 22-3.

[237] 5.63% in place of 5.71%.

[238] Hevert Direct, p. 22.

	HEVERT[239]	MURRAY[240]	GORMAN[241]	SCHAFER[242]
CAPM				
Risk-Free Rate	3.04, 3.68	3.17	4.10	3.2, 4.5
Beta	0.757, 0.760 0.758, 0.750	0.74, 0.73	0.76	0.77
Equity Market Premium	9.72, 10.45	6.20, 4.64	6.2, 7.3	5.4
RISK PREMIUM METHOD[243]				
Risk-Free Rate	3.04 3.68 5.45	4.13, 4.76	4.10, 4.71	N/A
Risk Premium	7.06 6.52 5.41	3.00, 4.00	4.41, 6.28 3.03, 5.03	N/A
TABLE 7 – COMPARISON OF CAPM AND RISK PREMIUM INPUTS.				

However impressive Mr. Hevert's explanation appears to be, the fact remains that his terminal growth rate is absurdly high. As Mr. Gorman testified, "Because Mr. Hevert's use of a historical real GDP growth rate does not reflect independent consensus economists' outlook for future real GDP growth, his nominal GDP growth rate used as his growth rate in his multi-stage DCF model overstates a reasonable multi-growth DCF return for his proxy group."[244]

The CAPM and the Risk Premium method are similar that, in each case, an equity market premium or risk premium is added to a bond yield in order to

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[239] Hevert Rebuttal, Sch's RBH-R11 and RBH-R12.

[240] *Staff RR Report,* pp. 42-44.

[241] Gorman Direct, pp. 27-32, 37.

[242] Schafer Direct, pp. 28-35; Sch. LCS-9. The beta value is the average of those used by Mr. Schafer.

[243] Including Mr. Murray's "Rule of Thumb."

[244] Gorman Rebuttal, p. 8.

determine the cost of equity. Here, the opportunity for manipulation is in the calculation of the equity market premium or risk premium.

Mr. Hevert used two equity market premia in his updated CAPM analysis, 9.72% and 10.45%. The *lower* of these values is 411 basis points *higher* than the average of the equity market premia used by the other analysts as shown in Table 7.[245] It is 352 basis points *higher* than the highest market equity premium used by the other analysts. Mr. Gorman observed, "My major concern with Mr. Hevert's CAPM analysis is his inflated market risk premium estimates."[246]

The same observation applies to Mr. Hevert's risk premiums. He used three: 5.41, 6.42 and 7.06.[247] The *lowest* of these, 5.41, is 112 basis points *higher* than the average of the risk premia used by Mr. Murray and Mr. Gorman.[248] However, it is *lower* than Mr. Gorman's highest risk premium at 6.28. However, the average of Mr. Hevert's three risk premia is 204 basis points *higher* than the average of the other analysts' risk premia.[249] Mr. Gorman criticized Mr. Hevert's Risk Premium Method as producing inflated results.[250]

A fair summary of these observations is that Mr. Hevert consistently used *higher* values for those inputs requiring professional judgment. In other words,

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[245] (6.2 + 4.64 + 6.2 +5.4) / 4 = 5.61.

[246] Gorman Rebuttal, p. 11.

[247] Table 7.

[248] *Id.* Mr. Schafer did not perform the Risk Premium Method.

[249] (7.06 + 6.52 + 5.41) / 3 = 6.33.

[250] Gorman Rebuttal, pp. 13-15.

where he had a choice, he chose higher rather than lower.[251] The result is higher outcomes.

Benchmarking

One way to look at the expert's recommendations is to compare them to what other utility regulatory commissions are doing around the country.

In that regard, Mr. Hevert testified, "there are two very recent and highly relevant benchmarks that provide a more comprehensive perspective: the range of recently authorized returns for other vertically integrated electric utility companies [Table 8] and the ROEs of 10.00 percent and 10.80 percent recently authorized by the Commission for natural gas utility companies."

However, Mr. Murray reported:

> According to RRA, the average authorized return on equity in the first three quarters of 2014 for electric utility companies was 10.00 % (based on 24 decisions) compared to a 2013 calendar year average of 10.02 %. Excluding the effect of the surcharge/rider generation cases in Virginia, the average allowed electric ROEs were 9.75 % for the first three quarters of 2014 and 9.80 % for the 2013 calendar year. This compares to an average allowed ROE of 10.17 % in 2012.[252]

Refining these numbers to reflect only "fully-litigated" cases, Mr. Murray testified, "Allowed ROEs for fully-litigated cases were 10.06 % through November 14, 2014, and 9.96 % for the 2013 calendar year. This compares to an average allowed ROE for fully-litigated cases of 10.10 % in 2012."[253]

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[251] Gorman Surrebuttal, p. 2: "Mr. Hevert's findings . . . reflect a bias toward a higher return on equity recommendation."

[252] *Staff RR Report,* p. 45.

[253] *Id.,* pp. 45-6.

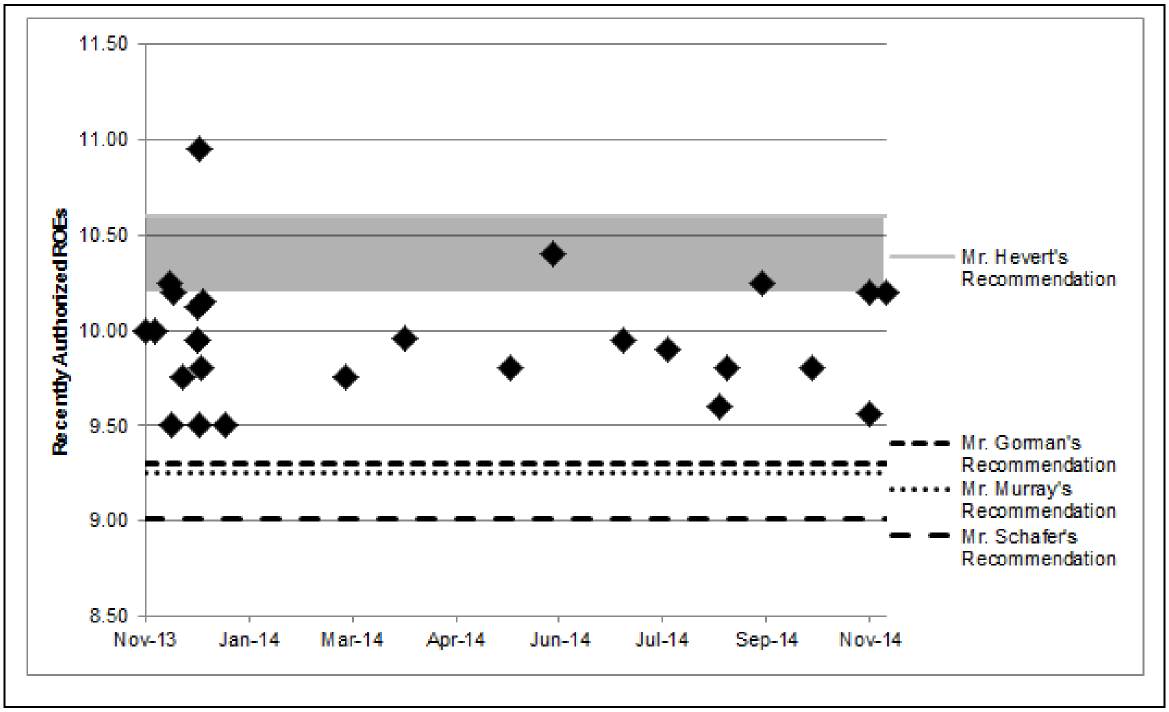

TABLE 8 – MR. HEVERT'S REBUTTAL TESTIMONY CHART 1.

Likewise, Mr. Gorman testified:[254]

Q. Based on a complete review of all authorized returns on equity for calendar year 2014, would the opposing witnesses' returns on equity be reasonable?

A. Yes. As shown on the attached Schedule MPG-SR-1, the authorized returns on equity for electric utility companies, both integrated and delivery companies, range from 9.17% to 10.4%, with an average of 9.76%. As shown on page 1 of Schedule MPG-SR-1, I excluded authorized returns on equity for utility rate cases where the commission either approved a settlement return on equity, or simply used the same return on equity in the current case as was approved in a prior case. Under these conditions, the industry average return for 2014 was 9.63%.

In summary, Mr. Hevert's recommendation is high when compared to ROEs recently authorized by other state utility regulatory commissions.

[254] Gorman Surrebuttal, p. 3.

Significant Capital Market Changes Since 2012

Among the things which the Commission must consider in the all-relevant-factor analysis required by statute are economic and capital market conditions as they apply to Ameren Missouri. An analysis, understanding and discussion of the capital market environment should allow the Commission to test the dependability and candor of the various witnesses providing opinions in this case. Staff freely recognizes that the Commission has considered the absolute value of Staff's cost of equity estimates to be too low for purposes of setting a fair and reasonable allowed ROE.[255] Staff recognizes that its cost of equity estimates are often benchmarked against the average allowed ROE information already discussed in this brief. Instead of manipulating its analysis to offer up a cost of equity estimate that Staff does not believe can be supported by an objective analysis of the capital markets, Staff performs an analysis of the change in the utility capital markets since 2012 with the understanding that the Commission partially used allowed ROE data at the time to decide an allowed ROE of 9.80% was reasonable for Ameren Missouri. There is no doubt that commissions deliberating on rate cases considering the same capital market data are having to review capital market evidence to decide if allowed ROEs deserve to be set lower than in the past. Staff has provided significant amounts of evidence that indicate ROEs should indeed be set lower.

Staff compared its cost of equity analysis in 2012 to its cost of equity analysis for the 2014 rate case. Staff did so based on two different sets of proxy

[255] David Murray, Tr. 21:1361.

groups. Staff's analysis in the Staff COS Report showed that the cost of equity had declined by up to 75 basis points since 2012.[256] Because interest rates had declined even further as this case proceeded and when Staff wrote rebuttal testimony, Staff's analysis of the relative change in Mr. Hevert's multi-stage cost of equity analysis supported a decline in the cost of equity in the range of 66 to 92 basis points.[257] Staff's analysis of the relative change in Mr. Gorman's multi-stage DCF analysis supported a decline of 66 to 73 basis points.[258] Although Mr. Schafer did not sponsor testimony in 2012, Staff noted the unusual step taken by a consumer advocate witness to actually adjust his initial cost of equity upward because he believed utility stocks were priced too high (cost of equity is too low).[259] Just reviewing the witnesses' DCF cost of equity results supports a lowering of Ameren Missouri's allowed ROE.

However, Staff did not stop there to provide the Commission evidence (and hopefully comfort) that it would be appropriate to lower Ameren Missouri's allowed ROE. Staff provided commentary directly from investors that indicate they expect commissions to lower allowed ROEs.[260] The reason? Lower interest rates and as a result, all-time high price-to-earnings ratios for electric utility companies.[261] While Company witness Mr. Hevert attempts to divert attention away from lower DCF cost of equity estimates by indicating he believes

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[256] *Staff RR Report,* p. 46.
[257] Murray Rebuttal, pp. 13-15.
[258] Murray Rebuttal, p. 19.
[259] Murray Rebuttal, p. 21.
[260] Murray Surrebuttal, pp. 25-28.
[261] *Id.*

the high valuation ratios of electric utility stocks cannot continue into the indefinite future,[262] his admission recognizes that utility stocks are expensive, which means that the cost of equity to the utility is cheap. The fact that Mr. Hevert did not make any argument similar to this in Ameren Missouri's 2012 rate case shows that conditions have changed and clearly supports Staff's recommendation to lower Ameren Missouri's allowed ROE due to a decline in the cost of equity. Investors recognize the ever widening gap between treasury yields and allowed ROEs and are factoring an expected compression in this gap when determining a fair price to pay for utility stocks. While Mr. Murray freely admitted that investors did not expect the Commission to allow an ROE consistent with his cost of equity estimate, Mr. Murray did provide information showing investors expect allowed ROEs to come down.[263]

Staff also provided specific Ameren Missouri bond yield information that allow the Commission to sort through some of the more convoluted arguments that often occur in the debate on estimating the cost of capital. Mr. Murray compared Ameren Missouri's bond yield information in 2012 to its bond yield information through as recently as February 2015. Comparing several months of average yields between 2012 and 2014 showed a decline in Ameren Missouri's debt yields of 35 to 50 basis points. Using the February 2015 bond yields

[262] Hevert Rebuttal, pp. 16-17.

[263] Murray Surrebuttal, pp. 25-28.

showed a decline of Ameren Missouri's debt yields of approximately 100 basis points.[264]

A comparison of the utility capital markets to the broader markets also supports Staff's recommendation to Ameren Missouri's allowed ROE to 9.25%. Consider -- for the twelve months ending December 31, 2014, the total return on the Dow Jones Industrial Average was 7.52%, the total return on the Standard & Poor's 500 ("S&P 500") was 14.69%, and the total return of companies classified as regulated utilities by the Edison Electric Institute ("EEI") was 32.86%.[265] On a quarterly basis, for the three months ending December 31, 2014, the total return on the Dow was 4.58%, the total return on the S&P 500 was 4.93%, and the total return of EEI's regulated utilities was 16.44%.[266] Average long-term utility bond yields have dropped to below 4.25%, while average 30-year U.S. Treasury yields have been approximately 3% or lower during the last quarter of 2014.[267]

This significant increase in utility stock prices reflects a steep decline in the cost of capital.[268] It is Staff's position that the COE for the electric utility industry has declined by at least 50 basis points, which forms the basis for Staff's recommendation to lower Ameren Missouri's allowed ROE to 9.25%. Electric utilities that are growing rate base are "cash-negative," meaning they cannot fund

[264] *Id.,* pp. 24-25.
[265] Murray Rebuttal, pp. 7-8.
[266] *Id.*
[267] *Id.*
[268] *Id.*

capital expenditures through return of capital.[269] Although Ameren Missouri's rate base has not (and is not projected to) grown at a high rate, it will need to finance this modest growth with a combination of retained earnings (and equity) and debt financing. A decline in the cost of capital, therefore, is good news for Ameren Missouri, particularly if it can convince the Commission to leave its ROE untouched, or even to raise it.

<u>Other Considerations</u>

Things are not nearly as good for Ameren Missouri's customers. Missouri's general economic condition, and particularly that of the counties that compose Ameren Missouri's service area, continues to experience challenges in the wake of the recession from December 2007 to June 2009.[270] The real GDP growth of Missouri has been smaller than that of the United States as a whole since the recession ended, and was even negative for Missouri in the year 2011.[271] Unemployment in Missouri is still above the pre-recession level.[272] Data appears to show the Missouri unemployment rate leveling-off above six percent and the national trend continuing on a downward trajectory.[273] From 2007 to 2013, the counties in the Ameren Missouri service area collectively experienced a 10.51% increase in average weekly wages.[274] This was slightly

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[269] Robert Hevert, Tr. 21:1158-60.

[270] *Staff's RR Report,* p. 3.

[271] *Id.*

[272] *Id.*

[273] *Id.*

[274] *Id.,* p. 5.

lower than the overall Missouri compounded increase in average weekly wages of 11.56%.[275]

During that same time period, the Consumer Price Index ("CPI") increased 12.35% while electric rates for Ameren Missouri's customers increased by 43.16%.[276] Ameren Missouri has also experienced inflationary pressure illustrated by a 17.84% increase in the Producer Price Index ("PPI") for Industrial Commodities from 2007 to 2013.[277] Ameren Missouri is currently requesting an additional $264 million or a 9.64% increase in rates.[278] From 2007 to 2013, the increase in average weekly wages for counties in the Ameren Missouri service area is less than one-quarter of the increase in electric rates for Ameren Missouri customers.[279] If Ameren Missouri receives its requested 9.64% increase, the increase in average weekly wages would be less than one-fifth of the increase in electric rates.[280] The customers that attended the Local Public Hearings universally opposed the proposed rate increase.[281]

Conclusion:

Based on all of the foregoing, Staff recommends that the Commission authorize an ROE for Ameren Missouri somewhere in the range of 9.0% to 9.5%, midpoint 9.25%, as recommended by Staff expert witness David Murray.

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[275] *Id.*
[276] *Id.*
[277] *Id.*
[278] *Id.*
[279] *Id.*
[280] *Id.*
[281] *See* Transcript, vols 2-13.

Mr. Murray's recommendation is based on direct evidence from the capital markets that clearly shows the cost of capital has declined since Ameren Missouri's 2012 rate case. The Commission need not get lost in the weeds of theory and subjective inputs to conclude that the cost of capital for Ameren Missouri has declined since 2012. The yields on Ameren Missouri's long-term debt have declined to as low as 3.5% in February 2015.[282] It is no coincidence that the price-to-earnings ratios of electric utilities have been trading at all-time highs at the same time. It isn't even disputed by any of the witnesses that as interest rates decline and utility stock prices increase, this means the cost of equity has declined. While Mr. Murray believes the cost of equity may be even lower, he benchmarked his recommendation against the Commission's allowed ROE for Ameren Missouri in 2012.

The weight of expert opinion adduced in this case favors an authorized ROE no higher than 9.5%, but the decline in the cost of equity since 2012 is more consistent with authorizing an ROE of 9.25%. This is strongly supported by economic data showing that Ameren Missouri's COE has dropped quite significantly, thus reducing its costs and raising its shareholders' wealth, while its customers continue to struggle in the wake of the Great Recession. Frankly, the people of Missouri deserve better.

The analyses performed by Ameren Missouri's expert witness, Robert Hevert, do not pass close scrutiny. In those areas where professional judgment was required, he chose to skew the data in his client's favor. Consistently,

[282] Murray Surrebuttal, p. 25.

Mr. Hevert selected higher values rather than lower values. His growth rates are too high; his market equity premia are too high. Where the results obtained by the other analysts are closely clustered and corroborate one another, Mr. Hevert's are isolated and suspiciously high. Perhaps these facts are not surprising in view of Mr. Hevert's lucrative practice of providing expert testimony for utility companies across the land.[283]

The Commission must balance the investors' interests against the ratepayers' interests. This issue is the largest single issue in this case and it is the issue where the Commission has the most discretion. That is not an unfettered discretion, however, because the Commission's decision must be supported by substantial evidence of record. As demonstrated by the foregoing, the substantial evidence in this record supports an allowed ROE no higher than 9.5%.

Kevin A. Thompson

9. Class Cost of Service, Revenue Allocation and Rate Design:

A. Which of the parties class cost of service results should the commission use to develop rates in this case?

The parties to this case submitted nine separate sub-issues in their *Joint List of Issues* under the issue of *Class Cost of Service, Revenue Allocation and Rate Design.* However, there is no need for the Commission to make a specific finding to resolve four of these issues, because the class-cost-of-service results of all parties are consistent in supporting the revenue-neutral, inter-class

[283] Robert Hevert, Tr. 21:1143-45.

shifts that do require a Commission determination.[284] All of the filed class-cost-of-service studies indicate that the Residential and LTs classes should receive a positive revenue neutral adjustment and the SGS, LGS, and SPS classes should receive a negative revenue neutral adjustment.

If the Commission does choose to enter specific findings on the class cost of service sub-issues regarding specific allocation methodology, Staff recommends that the Commission find in favor of the results of its Detailed Base Intermediate and Peak ("BIP") class-cost-of-service study because Staff's study methodology is the most reasonable, in that it recognizes the relationship between Ameren Missouri's generation fleet characteristics and the capacity and energy requirements of its load.[285] Staff's results are the most reasonable because Staff's Detailed BIP study relies on a more complex and thorough allocation of the cost of owning and operating Ameren Missouri's generation fleet than is done by the other parties' studies.[286]

B. How should any rate increase be collected from the several customer classes?

Staff's rate design recommendations in this case are based on a six-step process: (1) the Residential and LTs classes should receive a positive 0.50% revenue neutral adjustment and the SGS, LGS, and SPS classes should receive

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[284] The four issues that can all be resolved by determining which parties class cost of service results are sub-issues: allocation of generation fixed costs; allocation of production, operation and maintenance expense; off-system sales revenues; and fuel and purchase power costs.

[285] S. Kliethermes Rebuttal, p. 6, ll. 10-13.

[286] *Id.,* p. 5, ll. 1-3.

a negative 0.63% revenue neutral adjustment;[287] (2) assign directly to the applicable customer classes the portion of the revenue increase or decrease that is attributable to the amortization of energy efficiency programs form the Pre-MEEIA program costs;[288] (3) determine the amount of revenue increase awarded to Ameren Missouri that is not associated with Step 2;[289] (4) Order Ameren Missouri's rate schedules to be uniform for certain interrelationships among the non-residential rate schedules that are integral to Ameren Missouri's rate design;[290] (5) based on Staff's class-cost-of-service results and Commission policy on energy efficiency, the residential customer charge should stay at the current charge of $8.00 per month;[291] (6) each rate component of each class should be increased across-the-board for each class on an equal percentage basis after taking in to consideration Steps 1 through 5.[292]

In response to a question about the reasonableness of Staff's six-step rate design recommendation, Ameren Missouri's witness William R. Davis stated that Staff's recommendation was reasonable and that there was basic agreement between the parties on which classes are below cost of service and which are above cost of service and that it comes down to whether the Commission wants to move toward cost of service, and if so, to what degree.[293] Mr. Davis also

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[287] Scheperle Direct, pp. 3-4, ll. 19-21 & 1-2.

[288] *Id,.* at p. 4, ll. 4-8.

[289] *Id.,* at ll. 10-14.

[290] *Id.,* at ll. 16-25.

[291] *Id.,.* at 27-28.

[292] *Id.,* at 30-32.

[293] William R. Davis, Tr. 23:1494, ll. 4-11.

stated in his rebuttal testimony that Staff's rate design proposal contained moderate revenue neutral shifts, which has merit if one's goal is to bring rates more in line with cost-of-service results.[294]

Staff's rate design recommendation provides reasonable revenue neutral shifts which are in line with the majority of the class-cost-of-service studies performed in this case. Staff's recommendation provides moderate revenue neutral shifts whereas other parties' recommendations tend toward the extremes. If the Commission wishes to move rates toward class-cost-of-service results, which would be in-line with the principle of cost causation, Staff recommends using its six-step rate design process.

C. What should the residential customer charge be?

Staff recommends the Commission maintain the current residential customer charge at $8.00. Staff's recommendation is based on its study of cost causation, which determined that Ameren Missouri's cost of making service available to a residential customer allocates to $8.11 on a per-customer basis. Staff's recommendation is also consistent with the Commission's guidance in Ameren Missouri's last rate case proceeding where the Commission stated, "[s]hifting customer costs from variable volumetric rates, which a customer can reduce through energy efficiency efforts, to fixed customer charges, that cannot be reduced through energy efficiency efforts, will tend to reduce a customer's incentive to save electricity."[295] The Commission went on to state that, while

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[294] Davis Rebuttal, p. 3, ll. 14-15.

[295] *Report and Order,* Case No. ER-2012-0166, p. 110, ¶12.

admittedly increasing the residential customer charge by even one dollar would have a small effect on the payback period associated with energy efficiency efforts, increasing the customer charge would send the wrong message to customers.[296]

Staff's direct class-cost-of-service study, which was based on an ROR of 7.501%, resulted in a residential customer charge of $8.11.[297] Given the Commission's stated policy concerns in the last Ameren Missouri rate case, maintaining the current residential customer charge is not inconsistent with Staff's class-cost-of-service results.[298]

Ameren Missouri has proposed increasing all rate components by an equal percentage increase, which would result in a residential customer charge of $8.77 if the Commission granted the full 9.65% rate increase that Ameren Missouri has requested.[299] While Staff agrees that there is a reasonable relationship between the number of customers in a class and the percent of Ameren Missouri's distribution system that is related to serving that class, Staff does not think that it is reasonable to allocate those costs to the customer charge.[300] Distribution system costs may not vary with individual energy usage, but that does not necessarily mean that these costs should be collected in the customer charge as opposed to the energy charge. The distribution system

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[296] *Id.,* at p. 111, ¶ 13.

[297] R. Kliethermes Surrebuttal, p. 2, ll. 1 & 2.

[298] *Id.,* at ll. 2-4.

[299] Davis Direct, p. 17, ll. 7 & 8.

[300] R. Kliethermes Surrebuttal, p. 4, ll. 5-8.

costs that Ameren Missouri includes in the customer charge that Staff does not are FERC accounts 364-368. These accounts include poles, conductors, conduit, and line transformers; whereas Staff only includes FERC accounts 269 and 370. These accounts include services and meters, which are more specific to individual customers.[301] Ameren Missouri relied on a similar study in its last rate case. In the last rate case the Commission stated, "The chief difference between the various cost of service studies is the amount of distribution plant that each expert assigned to customer-related usage. Ameren Missouri's study tends to overstate the amount of the distribution system that would appropriately be allocated to customer-related usage."[302] The Commission went on to find that the residential customer charge recommendations of Staff and OPC were more reliable because those studies did not overstate the amount of distribution plant assigned to customer-related charges.[303]

Because Ameren Missouri overstates the amount of distribution system cost that should be included in the residential customer charge and the Commission stated an intent to promote energy efficiency in the last Ameren Missouri rate case, Staff recommends the residential customer charge remain at $8.00.

D. *Should the Commission approve Wal-Mart's proposed shift to increase the demand component of the hours-use rate design for Large General Service and Small Primary Service?*

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[301] *Id.,* at p. 4, note 4.

[302] *Report and Order,* Case No. ER-2012-0166, p. 110, ¶ 10.

[303] *Id.*

Staff does not support Wal-Mart's request at this time. There are approximately 11,000 customers in the LGS and SPS rate classes combined.[304] Specific customer impact analysis would need to be done before Staff could determine whether to support such a proposal on its merits.[305] Staff's rate design proposal recommendation was to increase all rate components across all the classes on an equal percentage basis.[306]

E. Should the Commission approve Wal-Mart's recommendation to require the Company to present analysis of alternatives to the hours-use rate design in its next rate case?

Staff believes that the hours-use rate design is an appropriate demand rate design that functions on the basis of the customer's monthly load factor;[307] however, Staff does not oppose specific customer information and analysis of alternatives to the hours-use rate design in future rate cases.

F. What methodology should the Commission use to allocate income tax expense among customer classes?

Staff recommends that for this case, the most reasonable method to allocate income tax expense to the various customer classes is to allocate based on class earnings, as Staff did in its class-cost-of-service study. Staff recommends allocating income tax expense based on class earnings because Ameren Missouri's method, which is based on net plant, would reduce Staff's residential customer charge by approximately $0.50.[308] Staff has determined

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[304] Fortson Rebuttal, p. 7, ll. 13-15.

[305] *Id.*

[306] *Id.,* at p. 8, ll. 9-11.

[307] *Id.,* at ll. 5-6.

[308] R. Kliethermes Surrebuttal, p. 5, ll. 5-7.

that Ameren Missouri's method for calculating income tax allocation as applied to the plant balances in this case would result in an unreasonable allocation.[309] This unreasonable allocation occurs with Ameren Missouri's method for allocating income tax because the depreciation reserve associated with FERC account 369 is currently in excess of its plant balance, which results in a negative value to be applied to the distribution services function.[310] As stated in the residential customer charge sub-section, both Staff and Ameren Missouri include FERC account 369 in calculating the residential customer charge.[311]

Since Ameren Missouri's income tax expense allocation methodology results in an unreasonable allocation, Staff recommends the Commission allocate income tax expense on the basis of class earning for purposes of this case.

--Alexander Antal.

10. Economic Development Rate Design Mechanisms:

A. Should the Commission expand the application of Ameren Missouri's existing Economic Development Riders?

The expansion of Ameren Missouri's Economic Development Riders needs further consideration beyond the current rate case. While Staff supports the promotion of economic development through the use of rate design mechanisms, the many issues raised by expansion of economic development

[309] R. Kliethermes Surrebuttal, p. 5, ll. 10-12.

[310] *Id.* at p. 5, note 8.

[311] *Id.*

riders would be best addressed by the formation of a collaborative process where all interested stakeholders would have the opportunity to participate.

On October 20, 2014, the Commission issued an order in this case directing Staff to research and analyze the use of rate design mechanisms to promote economic growth in various customer levels in locations that are currently underutilizing existing infrastructure.[312] In response, Staff's Class Cost of Service Report included analysis of current economic development riders, and considered the potential benefits and problems with expanding these riders.

Staff noted that, presently, all of the regulated electric utilities in Missouri have economic development rider programs.[313] Since June 1, 2007, Ameren Missouri has been operating with two economic development riders: Economic Development and Retention Rider ("EDRR") and Economic Redevelopment Rider ("ERR").[314] Customer participation in Ameren Missouri's program has been limited to only one participant, who has not yet elected to receive its discount under the EDRR rider.[315] Due to a lack of customer participation in Ameren Missouri's riders, Staff was unable to make any conclusions about the success of Ameren Missouri's current program.[316]

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[312] *Order Directing Consideration of a Certain Rate Design Question,* issued October 20, 2014.

[313] Ex. 201, CCOS, pg. 48, lines 17-18.

[314] *Id.* at pg. 53, lines 6-7.

[315] *Id.* at pg. 53, lines 23-25.

[316] *Id.* at pg. 53, lines 25-26.

Expansion of economic development riders raises many cost, quantification, and administration concerns that must be considered. For example, Staff explored expanding the riders—which are currently only offered to industrial/commercial customers—to other classes, particularly residential.[317] On this issue, Staff noted that residential customers have lower usage than other customer classes.[318] Thus, any benefit residential customers might receive from participation in a program would likely be small.[319] Further, Staff noted that the cost of administering a residential economic development rider program is currently unknown. It is possible that administration costs of such a program could be more than any cost benefit residential customers would receive.[320]

Another concern that needs more discussion is the geographic locations that would be subject to an economic development rate design. Ideally, application of economic rate design mechanisms would focus on areas with underutilization of existing infrastructure.[321] Staff has explored possible methods of determining "underutilization" in this context. Ameren Missouri provided Staff with data on loading and capacity of Feeders and Distribution substations in the St. Louis metro region.[322] Staff conducted a preliminary review of this data, and noted that Ameren Missouri is able to switch between

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[317] *Id.* at pp. 48-50.

[318] *Id.* at pg. 46, line 5.

[319] *Id.* at pg. 46, line 6.

[320] *Id.* at pg. 46, lines 2-4.

[321] *Id.* at pg. 50, lines 22-24.

[322] *Id.* at Schedule DIB 2-1-2-32.

some circuits within the distribution systems, which makes it difficult to assess which circuits are truly "underutilized."[323] Further analysis of this data, along with consideration of population movements,[324] and easily identifiable markers like zip codes, are important characteristics of quantifying "underutilization" that should be explored in a collaborative process in another docket.[325]

Staff also had administration concerns regarding eligibility of economic development programs. Staff does not currently have the resources to provide constant oversight of the eligibility assessments of applicants.[326] Therefore, an economic development program needs to be properly designed so that eligibility is clear and transparency is promoted.[327] Staff believes that refinement of the eligibility criteria is an issue that needs to be addressed with all stakeholders in a collaborative process.[328]

B. Should the Commission modify Ameren Missouri's existing Economic Development Riders to require recipients to participate in the Company's energy efficiency programs?

Not presently. In analyzing Ameren Missouri's current economic development riders, Staff noted that there has been only one participant.[329] Staff agrees with the point that Ameren Missouri's expert witness

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[323] *Id.* at pg. 47, line 14-19.

[324] Tr. 24:1728, lines 10-22.

[325] Ex. 201, CCOS, pg. 47, lines 22-24; pg. 48 lines 1-7.

[326] *Id.* at pg. 48, lines 13-15.

[327] *Id.* at pg. 50, lines 12-13.

[328] *Id.* at pg. 50, line 16-17.

[329] *Id.* at pg. 53, lines 23-25.

William R. Davis made in his Supplemental Direct Testimony[330] and Rebuttal Testimony,[331] that adding additional eligibility criteria now will only further hinder participation. Similarly, Staff also supports Mr. Davis's assertions that a collaborative would provide an opportunity to further discuss eligibility criteria concerns stakeholders may have.[332]

C. Should the Commission open a docket to explore the role economic development riders have across regulated industries (i.e. water, electric, natural gas) and/or to further explore issues raised by parties in this case and issues the Commission inquired about at the beginning of the case?

Yes. A docket should be opened to address economic development rider program design and implementation issues that have been discussed. Staff further believes that the open docket should entail a collaborative process that allows all interested and affected parties an opportunity to participate.

--*Jaime Myers*

11. Lighting Issues:

A. Cities' Street Lights Issue:

1. *Can the Commission mandate or require that the Company sell its street lights to the Cities?*

2. *Should the Commission approve a revenue-neutral adjustment between customer-owned and Company-owned lighting rates?*

3. *Should the Commission eliminate the termination fees from the Ameren Missouri-owned lighting rate?*

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[330] Ex. No. 8.

[331] Ex. No. 9.

[332] *Id.*

The Cities currently receive electric service from Ameren Missouri under the 5(M) tariff for Street and Outdoor Area Lighting – Company-Owned. The Cities want to have the option to purchase these light fixtures from Ameren Missouri at fair market value and, in turn, to receive electric service from Ameren Missouri under the 6(M) tariff for Street and Outdoor Area Lighting – Customer-Owned, which would reduce their monthly payments to Ameren Missouri. So far, Ameren Missouri and the Cities are unable to reach agreement.[333] The Staff takes no position on this matter in this case. The Staff does not have a response to the Ameren Missouri assertion that the class of customers that includes cities that own their street lights is under-recovering its share of the total cost of street lighting,[334] as that issue came up very late in the proceedings and the Staff has not performed an independent cost-allocation study to verify or refute that claim. The Staff generally does not believe that it would be appropriate for the Commission to require Ameren Missouri to sell street lighting facilities to the cities who wish to purchase them, but does support a two-step process wherein Ameren Missouri and a city agree to transfer ownership to the city and then the transaction is presented to the Commission for approval.

B. LED Street Lighting:

Should the Commission order Ameren Missouri to continue to study the cost-effectiveness of replacement of all or parts of existing company-owned street lights with LED lights, and, no later than twelve (12) months

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[333] *See* City of O'Fallon witness Bender Surrebuttal, p. 2, ll.14-17; City of Ballwin witness Kuntz Direct, p. 2, ll. 7-12; Ameren Missouri witness Davis Rebuttal, p. 38, ll. 2-7.

[334] *See* Ameren Missouri witness Davis Rebuttal, p.39, l.20 - p.41, l.18.

following the Commission's Report and Order in this case, to file either proposed LED lighting tariffs or an update to the Commission on when it will file a proposed LED lighting tariff to replace existing company-owned street lights?

On March 19, 2015, the Commission issued an *Order Approving Non-Unanimous Stipulation and Agreement Regarding MEEIA Low Income Exemption and LED Street Lighting Issues.*[335] The *Stipulation and Agreement* included the following language concerning LED lighting:

> The Signatories agree Ameren Missouri should continue updating its annual evaluation of the cost effectiveness of company-owned LED street and outdoor area lighting pursuant to the terms of the Commission's *Order Approving Tariff* in File No. EO-2013-0367. The Company further agrees to include an estimation of the potential carbon dioxide reductions associated with LED street and outdoor area lights.

In the Staff's opinion, this satisfactorily addresses the issue and no Findings of Fact or Conclusions of Law pertaining to the substance of this issue are necessary.

C. Other Lighting Tariff issues:

Should the Commission order the Company to eliminate the 7(M) lighting class (Municipal Incandescent Street Lighting)?

Staff supports the Company's proposal to eliminate service classification 7(M) as it has become unnecessary. No customers presently take service under that classification, with all of the lighting customers classified as 5(M) or 6(M).[336] The Staff supports the Commission ordering Ameren Missouri to eliminate the 7(M) rate class in its compliance tariff filing.

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[335] *See* EFIS entry 465.

[336] *See* Davis Rebuttal, p.52, ll.2-13.

--Colleen M. "Cully" Dale.

12. Labadie Electrostatic Precipitators:

Should the Company's investment in electrostatic precipitators installed at the Labadie Energy Center be included in the Company's rate base?

The final cost for the ESP project, to be included in the cost of service, is $183,282,825. Staff has included the project's actual costs except for $408,048 for 94 ESP plates that were not installed in Unit 2 due to damage that occurred to the plates while they were stored on site at the Labadie Energy Center. The adjustment includes the cost of the plates, plus all applicable accrued AFUDC, less the scrap salvage value that Ameren Missouri received for the damaged plates. The costs associated with the damaged plates were imprudently incurred because Ameren Missouri and its contractor, Alberici, did no analysis when storing the plates, despite the caution in the instructions provided by the manufacturer, Teco, and their presumed knowledge of the fact that strong winds do occur at Labadie. Staff takes no other position related to this issue other than that put forward above.

--*Cydney D. Mayfield.*

13. Fuel Adjustment Clause ("FAC"):

A. Did the Company fail to comply with the "complete explanation" provisions of 4 CSR 240-3.161(3)(H) and (I) and, if so, would this justify the elimination of the Company's fuel adjustment clause?

B. Did the Company fail to provide information on the magnitude, volatility and the Company's ability to manage the costs and revenues that it proposes to include in its FAC and, if so, would this justify the elimination of the Company's fuel adjustment clause?

C. If the FAC continues should the sharing percentage be changed to 90%/10%?

D. Should transmission charges associated with power that is generated by Ameren Missouri for its load or transmission charges associated with off-system sales be included in the FAC as transportation of "purchased power"?

E. If the FAC continues, what costs and revenues should be included in the Company's FAC:

1. Should only fuel and purchased power costs, transportation of the fuel commodity, transmission associated with purchased power costs and off-system sales revenues be included?

2. If costs and revenues other than those listed in item 1 above are included in the FAC, should cost or revenue types in which the Company has incurred less than $390,000 in the test year be included, and what charges and revenues from MISO should be included?

3. Should transmission revenues continue to be included in the FAC?

All Fuel Adjustment Clause ("FAC") issues between Staff and the Company have been resolved. Staff does not support the efforts by other parties to significantly modify or even discontinue the FAC. Staff recommends that the Commission approve continuation of Ameren Missouri's FAC with the below modifications:

- Ameren Missouri's FAC tariff sheets should be revised to reflect re-basing of the Winter and Summer Base Factors;
- Ameren Missouri's FAC tariff sheets should be revised to clarify that the fuel costs related to the Company's landfill gas generating plant known as Maryland Heights Energy Center are excluded from the FAC; and

- Ameren Missouri should continue to provide additional monthly filings that will aid the Staff in performing FAC tariff, prudence and true-up reviews.

--*Kevin A. Thompson.*

14. Noranda Rate Design Issues:

A. Is Noranda experiencing a liquidity crisis such that it is likely to cease operations at its New Madrid smelter if it cannot obtain relief of the sort sought here?

1. If so, would the closure of the New Madrid smelter represent a significant detriment to the economy of Southeast Missouri, to local tax revenues, and to state tax revenues?

2. If so, can the Commission lawfully grant the requested relief?

3. If so, should the Commission grant the requested relief?

Staff did not perform an independent investigation, evaluation or analysis of Noranda's financial condition and therefore takes no position as to whether or not Noranda is experiencing a liquidity crisis such that it is likely to cease operations at its New Madrid smelter if it cannot obtain relief of the sort sought here. Staff does note, however, that Noranda's position is generally corroborated by the unrefuted evidence adduced showing a very significant decline in the number of operating aluminum smelters in the United States since 1980.[337] Staff notes that the competent and substantial evidence of record

[337] Fayne Direct, p. 3: "In the U.S. in 1980, there were 32 smelters, producing more than 5 million metric tons. Today, there are only 8 smelters operating in the U.S., producing about 1.8 million metric tons annually. In every instance, the smelter shut down because of high power costs (HWF Exhibit-1 shows the U.S. smelters currently in operation)."

would support a finding either in the affirmative or the negative on the question of the imminence of Noranda's closing.

Staff agrees that the closure of the New Madrid smelter would represent a significant detriment to the economy of Southeast Missouri, to local tax revenues, and to state tax revenues.[338] The evidence adduced by Noranda on this point was unrefuted and is, frankly, a matter of common sense.

It is Staff's position that, if the Commission finds that Noranda is experiencing a liquidity crisis such that it is likely to cease operations at its New Madrid smelter in the absence of significant rate relief, the Commission could lawfully grant a load retention rate to Noranda so long as the additional costs imposed thereby on Ameren Missouri's other customers are *less* than the additional costs they would experience if Noranda ceased operations.

Section 393.130.3, RSMo., provides:

> No gas corporation, electrical corporation, water corporation or sewer corporation shall make or grant any undue or unreasonable preference or advantage to any person, corporation or locality, or to any particular description of service in any respect whatsoever, or subject any particular person, corporation or locality or any particular description of service to any undue or unreasonable prejudice or disadvantage in any respect whatsoever.

A load-retention rate, although below cost of service, is nonetheless reasonable and non-discriminatory if it confers a commensurate benefit on other ratepayers and marginal costs are recovered.[339]

[338] Haslag Direct, including Report, and Haslag Surrebuttal.

[339] ***Public Service Co. of Colorado v. Trigen-Nations Energy Co., L.L.L.P.,*** 982 P.2d 316, 323 (Colo.,1999): "By allowing a public utility to offer contract rates below the prevailing tariffs for retail electric service in its certificated territory, section 40–3–104.3 provides a means by which a

B. Would rates for Ameren Missouri's ratepayers other than Noranda be lower if Noranda remains on Ameren Missouri's system at the reduced rate?

Under test year conditions, at a rate of $32.50 with no participation in the FAC, the rates for Ameren Missouri's other ratepayers would be *lower* if Noranda remains on Ameren Missouri's system, than if Noranda ceased service with Ameren Missouri.[340] This analysis is premised on no change to: (1) the wholesale power prices used in Staff's modeling, (2) the level of transmission costs such as MISO 26a, average ancillary service costs, and MISO charges assessed on load or load ratio share, and (3) Ameren Missouri's cost of fuel and purchased power. If these or other conditions change, other ratepayers' rates would vary.

C. Would it be more beneficial to Ameren Missouri's ratepayers other than Noranda for Noranda to remain on Ameren Missouri's system at the requested reduced rate than for Noranda to leave Ameren Missouri's system entirely?

Under test year conditions, assuming no change to the (1) wholesale power prices used in Staff's modeling, (2) the level of transmission costs such as MISO 26a, average ancillary service costs, and MISO charges assessed on load or load ratio share, and (3) Ameren Missouri's cost of fuel and purchased power,

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regulated electric, gas, or steam utility may retain existing customers who are contemplating reduction or elimination of their power purchases from it. See § 40–3–104.3. These lower-than-standard rates, referred to as **load retention rates**, function to retain existing customers for participation in the rate base allocation and recovery of fixed and variable costs. *See* Robert L. Swartwout, *Current Utility Regulatory Practice From a Historical Perspective,* 32 Nat. Resources J. 289, 316–17 (1992). The principle is that all customers benefit from lower rates through greater economies of scale when the public utility retains customers, especially large-use customers who may have the ability to reduce or eliminate demand by generating their own power within plant boundaries or by other legal means."

[340] Sarah Kliethermes, Tr. 35:3003-4, testified that the incremental cost to serve Noranda was $31.50 at Noranda's meter. $32.50 is the incremental cost plus $1.00 of margin. The average wholesale power price used in Staff's production modeling is $28.29.

rates for Ameren Missouri's other ratepayers would be lower if Noranda remains on Ameren Missouri's system at a rate of $32.50 and without participation in the FAC, than if Noranda ceased receipt of service from Ameren Missouri.[341] If these or other conditions change, other ratepayers' rates would vary.

D. Is it appropriate to redesign Ameren Missouri's tariffs and rates on the basis of Noranda's proposal, as described in its Direct Testimony and updated in its Surrebuttal Testimony?

1. If so, should Noranda be exempted from the FAC?

2. If so, should Noranda's rate increases be capped in any manner?

3. If so, can the Commission change the terms of Noranda's service obligation to Ameren Missouri and of Ameren Missouri's service obligation to Noranda?

4. If so, should the resulting revenue deficiency be made up by other rate payers in whole or in part?

Ameren Missouri is entitled to a reasonable opportunity to earn a fair rate of return, so known revenue deficiencies would need to be made up by other ratepayers. However, other ratepayers should not bear responsibility for Ameren Missouri's price risk in obtaining wholesale power to serve Noranda.

5. If so, how should the amount of the resulting revenue deficiency be calculated?

6. If so, can the resulting revenue deficiency lawfully be allocated between ratepayers and Ameren Missouri's shareholders?

i. How should the revenue deficiency allocated to other ratepayers be allocated on an interclass basis?

[341] *Id.*

ii. How should the revenue deficiency allocated to other ratepayers be allocated on an intra-class basis?

7. If so, what, if any, conditions or commitments should the Commission require of Noranda?

E. What is Ameren Missouri's variable cost of service to Noranda?

Under test year conditions, assuming no change to the (1) wholesale power prices used in Staff's modeling, (2) the level of transmission costs such as MISO 26a, average ancillary service costs, and MISO charges assessed on load or load ratio share, and (3) Ameren Missouri's cost of fuel and purchased power, using the wholesale cost of power assumed in Staff's fuel run, Ameren Missouri's variable cost of service to Noranda is approximately $118,777,387.[342] This equates to a per MWh cost at Noranda's meter of $28.29.[343] The four-year average wholesale cost as relied upon by the Commission in Case No. EC-2014-0224 was $31.50. For purposes of determining marginal cost, $31.50 is the most reasonable amount contained in the record.[344]

1. Should this quantification of variable cost be offset by an allowance for Off-System Sales Margin Revenue?

2. What revenue benefit or detriment does the Ameren Missouri system receive from provision of service to Noranda at a rate of $32.50/MWh?

Under test year conditions, assuming no change to the (1) wholesale power prices used in Staff's modeling, (2) the level of transmission costs such as MISO 26a, average ancillary service costs, and MISO charges assessed on load

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[342] S. Kliethermes Surrebuttal, App. 1-6.

[343] Ex. 246, p. 2.

[344] Sarah Kliethermes, Tr. 35:3003-4.

or load ratio share, and (3) Ameren Missouri's cost of fuel and purchased power, using the wholesale cost of power assumed in Staff's fuel run, Noranda would contribute approximately $40,595,593[345] in excess of what Ameren Missouri would spend to procure that energy, at a rate of $32.50/MWh if Noranda remains on Ameren Missouri's system at a rate of $32.50.[346] If these or other conditions change, the estimated benefit or detriment will vary.

F. Should Noranda be served at rate materially different than Ameren Missouri's fully distributed cost to serve them? If so, at what rate?

The answer depends on whether or not the Commission believes that, without rate relief, Noranda is likely to close in the near future.

- If the Commission believes that Noranda is likely to close, then Staff recommends that the Commission grant a properly-formulated load-retention rate to Noranda as discussed in more detail below.
- If the Commission does NOT believe that Noranda is likely to close, then Staff recommends rates be set on the basis of fully-allocated cost of service. All class-cost-of-service studies indicated Noranda's current revenues paid for service are insufficient. Staff recommends a modest move toward paying its cost of service, which would require Noranda revenues in the amount of approximately $167,032,790, to be applied as an equal

[345] $1.00 x Noranda's Test Year total MWh.

[346] Four-year average wholesale cost plus $1.00.

percentage increase to all existing LTS tariff rate components. While Staff does not recommend billing Noranda on an energy-only basis, this class revenue requirement equates to an energy-only rate of approximately $39.78/MWh, at Noranda's meter.

G. Is it appropriate to remove Noranda as a retail customer as proposed by Ameren Missouri in its Rebuttal Testimony?

1. Can the Commission cancel the Certificate of Convenience and Necessity that was granted for Ameren Missouri to provide service to Noranda and, if so, would the cancellation of the CCN be in the public interests?

Staff does not object to Ameren Missouri and Noranda reaching a reasonable agreement at a reasonable price on reasonable terms. However, under Ameren Missouri's proposal, all risk of the contract price not covering Ameren Missouri's actual cost to provide wholesale service to Noranda would fall on Ameren Missouri's captive retail customers.[347] A properly-designed escalator provision could protect all parties.[348] For example, Ameren Missouri could index Noranda's wholesale price to the market price of energy for Noranda - including transmission and other expenses - and periodically adjust Noranda's rate accordingly. Absent such an adjustment mechanism, a reasonable rate for Ameren Missouri to serve Noranda at wholesale pursuant to a long-term contract would possibly be higher than the fully-allocated cost of service calculated by Staff and other parties, as the cost-of-service calculations are directed at a snapshot in time and are reflective of current energy and transmission costs.

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[347] S. Kliethermes Surrebuttal, App. 1.

[348] *Id.*

Until Ameren Missouri has provided to Staff an analysis that takes into consideration all necessary cost aspects associated with the proposed agreement, Staff can only recommend that the Commission not approve the transaction.

2. Can the Commission grant Ameren Missouri's proposal since notification regarding the impact of this proposal on its other customers' bills was not provided to Ameren Missouri's customers?

Ameren Missouri's customers received ample notification of the commencement of this general rate case. Additionally, the existence of § 91.026, RSMo., has, since its enactment, served as notice to all the world that Noranda may elect to leave Ameren Missouri's system.

3. If the Commission grants Ameren Missouri's proposal, should the costs and revenues flow through the FAC?

Staff cannot provide specific recommendations until Noranda and Ameren Missouri have permitted Staff to review the actual terms of their proposed wholesale contract. However, Staff recommends that should Noranda become a wholesale customer of Ameren Missouri, due to the size of Noranda's load, it will likely be necessary to allocate the cost of service of Noranda to the wholesale jurisdiction. If this is necessary, Staff recommends that the Ameren Missouri Missouri-jurisdictional revenue requirement otherwise found in this case be reduced by this wholesale jurisdictional amount. Staff does not recommend that any such contract be flowed through the FAC, thus slight modifications to the Ameren Missouri FAC tariffs will be necessary if Ameren Missouri and Noranda do enter into a wholesale contract.

4. Can Ameren Missouri and Noranda end their current contract without approval of all of the parties to the Unanimous Stipulation and Agreement in the case in which Ameren Missouri was granted the CCN to serve Noranda?

Nothing in the *Unanimous Stipulation and Agreement* approved by the Commission in Case No. EA-2005-0108, or in the Commission's order of March 10, 2005, approving that *Unanimous Stipulation and Agreement,* purports to require the approval of the signatory parties for Noranda and Ameren Missouri to end their contract. It is, therefore, Staff's opinion that Noranda and Ameren Missouri may mutually agree to end their contract at any time.

Introduction:

If the Commission believes that Noranda's financial condition is so precarious that it will close its doors should it not obtain rate relief from the Commission in this case, then Staff recommends that the Commission authorize a properly-designed, load-retention rate for Noranda. On the other hand, if the Commission believes that Noranda's financial condition is not that precarious and that Noranda will continue as a retail customer of Ameren Missouri indefinitely in the future, even in the absence of rate relief, then Staff recommends that the Commission set Noranda's rate at $39.83 per MWh at Noranda's meter.[349] This rate would reflect a slight increase above the system-average increase as a move to recognizing the current under-contribution of the LTS class to its fully-allocated cost of service.[350]

[349] S. Kliethermes Rebuttal, p. 8.

[350] *See Staff's Rate Design ("RD") Report,* pp. 1-2 and Tables 1 and 2.

Discussion:

<u>Noranda's Financial Condition</u>

In this case, as in the two complaint cases that it brought last year,[351] Noranda Aluminum seeks a reduced rate for electric service on the grounds that, without it, it will close its doors. Given its limited resources, the Staff has not independently investigated Noranda's financial condition and Staff expresses no opinion on that issue. Staff notes that the record would support either of two inconsistent findings by the Commission: that Noranda is in precarious financial circumstances such that its closure is imminent or that Noranda is in much the same financial condition that it has been in since it joined Ameren Missouri's retail system in 2005 and that its imminent closure, therefore, is unlikely

<u>A Load-Retention Rate for Noranda</u>

Staff estimates that, should Noranda close its doors, Ameren Missouri's remaining retail customers would suffer a detriment of about $34 million on an annual basis, using wholesale power prices consistent with the prices used by Ameren Missouri and Staff in calculating fuel and purchased power expense in this case.[352] An acceptable load-retention rate design, therefore, must contribute *more* than $34 million above incremental cost on an annual basis.

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[351] Case Nos. EC-2014-0223 and EC-2014-0224.

[352] S. Kliethermes Rebuttal, p. 13: "I estimate Ameren Missouri's other customers would be obligated to make up about $159 million in revenues currently generated by Noranda, but based on the direct-filed revenue requirement in this case, I would expect that amount to be offset by approximately $125 million in additional OSS revenues. Taken together, I would estimate other classes' net cost of service to increase by approximately $34 million."

Incremental cost is $31.50 per MWh.[353] At $32.50, which is the reasonable estimate of the incremental cost to obtain wholesale power to serve Noranda plus $1.00, Staff calculates that Noranda would contribute approximately $14.5 million on an annual basis.[354] Additionally, because conditions will not remain static over time, an acceptable load-retention rate design must include some mechanism to pass the effect of changed conditions on to Noranda.[355] Such a mechanism could take the form of either "continued participation in the FAC or development of a Noranda-specific FAC[.]"[356] Another option would be "a market indexing mechanism,"[357] to avoid the inequity of allowing Noranda to share the benefit of Off-System Sales Revenue ("OSSR"), which is part of the FAC.[358]

Ms. Kliethermes described the framework of a Noranda-specific FAC:

> If a Noranda-specific FAC is adopted, Staff recommends it be indexed to Ameren Missouri's costs in providing service to Noranda that would not be incurred but-for it providing service to Noranda. Those costs are the wholesale cost of energy, the cost of supportive ancillary services, and MISO transmission charges, including but not limited to Schedules 26 and 26a. The base of such a mechanism would be the wholesale energy price used in Staff's direct-filed revenue requirement ($28.08/MWh at Noranda's meter), plus the actual transmission and other load-based charges for the twelve months ending July 31, 2014 ($.92/MWh at Noranda's meter), for a total of $29.00/MWh, at Noranda's meter, resulting in a contribution to offset the costs of other customers of

[353] Sarah Kliethermes, Tr. 35:3008-9.

[354] S. Kliethermes Rebuttal, p. 13.

[355] *Id.,* at 16.

[356] *Id.*

[357] Sarah Kliethermes, Tr. 35:3009.

[358] *Id.,* pp. 3009-10; S. Kliethermes Rebuttal, p. 16 n. 8.

$3.50/MWh, or approximately $14.5 million, annually.[359]

Ms. Kliethermes went on to explain that the mechanism "would be adjusted once a year, to bill the difference between the base sum of (A+B+C)/Noranda's energy in MWh at Noranda's meter, and that year's sum of (A+B+C)/Noranda's energy in MWh at Noranda's meter."[360]

A	Noranda's hourly load (at transmission) for Applicable Period	x	AMMO.UE.Load Zone DA LMP
B	Noranda's total energy in MWh at transmission	x	Average Ameren Ancillary Service Costs for Applicable Period
C	Noranda's total energy in MWh at transmission	x	MISO Transmission Charges in Effect at End of Period (prorated if change during Applicable Period)
Chart from S. Kliethermes Rebuttal, p. 17.			

Conclusion:

In conclusion, Staff states that, if the Commission believes that Noranda will close its doors should it not obtain rate relief from the Commission in this case, then Staff recommends that the Commission authorize a properly-designed, load-retention rate for Noranda. On the other hand, if the Commission does not believe that Noranda is likely to close without rate relief, then Staff recommends that the Commission set Noranda's rate at $39.83 per MWh at Noranda's meter.[361]

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[359] S. Kliethermes Rebuttal, pp. 16-7.

[360] *Id.,* p. 17.

[361] S. Kliethermes Rebuttal, p. 8.

15. Questions Raised by Commissioner Hall:[362]

> A. *What is the risk concern that Ameren and Noranda have concerning the wholesale agreement proposal that Ameren's put forth?*
>
> > 1. *To what extent can the Commission in an Order or a tariff mitigate or eliminate that risk?*
> >
> > 2. *To what extent can the General Assembly mitigate or eliminate that risk?*

The risk concerns the possible financial consequences of a successful legal challenge of a conversion of Noranda from retail load to wholesale load.[363] Because such a conversion would be unprecedented, the outcome of a legal challenge cannot be predicted with any certainty. The differential between retail rate and market price would be substantial and, given the size of Noranda's load, would quickly amount to many millions of dollars. The risk that Ameren Missouri and Noranda decided they could not take is the risk that one or the other of them might have to bear the loss of these millions of dollars.

Although there is a statute authorizing just such a conversion, that statute has never been tested in court.[364] If the Noranda conversion went forward and a challenge was eventually sustained many months later, an enormous amount of money would be at stake. If Noranda was required to pay this money to Ameren Missouri on the theory that the conversion was unlawful and that the service provided to Noranda subsequently should have been billed

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[362] At the hearing, Commissioner Hall announced four questions that he specifically wanted to be addressed in the parties' briefs. Tr. 35:3080.

[363] By "wholesale," Staff means a customer served at market price rather than at a cost-of-service rate. *See* Maurice Brubaker, Tr. 33:2660, 2667, 2675-76.

[364] Section 91.026, RSMo.

at the retail rate, Noranda would be ruined. Bankruptcy would be the certain result and little of the money would, in fact, ever be paid. Ameren Missouri, on the other hand, might well be required to refund any additional amounts that it had collected from its other retail customers, leaving it with a large financial loss.

There appears to be nothing that either the Commission or the General Assembly can do to mitigate or eliminate this risk. The General Assembly has already enacted a statute for Noranda; but the General Assembly cannot control what the courts may do if the statute is challenged. That is the very central element of the problem. The Commission can only take such actions as its organic statutes permit. Under those statutes, the Commission lacks jurisdiction to allow Noranda, a retail customer, to become a wholesale customer. Additionally, sales of electricity at wholesale are by definition a matter of federal jurisdiction rather than state jurisdiction.

B. How and to what extent would ratepayers be harmed by moving Noranda to wholesale service?

1. Can the Commission or General Assembly mitigate or eliminate that harm?

If Noranda were served at market price, then it would contribute little or nothing toward Ameren Missouri's fixed costs, resulting in a rate hike for the remaining retail customers. That harm could be mitigated only if the market price charged to Noranda included an adder or surcharge of some sort intended to defray the additional costs charged to Ameren Missouri's retail ratepayers. However, since sales of electricity at wholesale are by definition a matter of federal jurisdiction rather than state jurisdiction, neither the Commission nor the General Assembly could impose such an adder or surcharge.

> *C. What would be the effect on Ameren and its customers of eliminating the 12(M) adjustment of off-system sales in the current FAC tariff? Is it appropriate to do so?*

The 12(M) adjustment applies to the definition of Off-System Sales Revenue ("OSSR") in Ameren Missouri's FAC tariff.[365] It provides:

> <u>Adjustment For Reduction of Service Classification 12(M) Billing Determinants:</u>
>
> Should the level of monthly billing determinants under Service Classification 12(M) fall below the level of normalized 12(M) monthly billing determinants as established in Case No. ER-2010-0036 an adjustment to OSSR shall be made in accordance with the following levels:
>
> a) A reduction of less than 40,000,000 kWh in a given month
> - No adjustment will be made to OSSR.
>
> b) A reduction of 40,000,000 kWh or greater in a given month
> - All Off-System revenues derived from all kWh of energy sold off-system due to the entire reduction shall be excluded from OSSR.

This adjustment was formerly referred to as Factor "N" elsewhere in the tariff.:[366]

> N = The positive amount by which, over the course of the Accumulation Period, (a) revenues derived from the off-system sale of power made possible as a result of reductions in the level of 12(M) sales (as addressed in the definition of OSSR above) exceeds (b) the reduction of

[365] Mo. P.S.C. No. 6, Original Sheet 70.4, effective July 31, 2011. *See also* Original Sheet 71.3.

[366] *Id.*

> 12(M) revenues compared to normalized 12(M) revenues as determined in Case No. ER-2010-0036.

Factor N, the 12(M) load-loss adjustment, was added to the tariff in the first general rate case following the ice storm of January 2009. It provides that, in the event of a load loss of a certain magnitude, the revenue from off-system sales up to that magnitude would not be subject to the 95-5 sharing mechanism. The purpose of the N Factor is to prevent a reoccurrence of the circumstances in which Ameren Missouri found itself following the January 2009 ice storm, when Noranda was unable to take two-thirds of the energy that Ameren Missouri had expected to sell to Noranda and the Company was forced to share the revenue received from the replacement power contracts it made. The result was a substantial loss to Ameren Missouri.

As long as Noranda is a retail customer on Ameren Missouri's system, it will not be appropriate to remove the N Factor from the Company's FAC tariff. Why? Because another ice storm could occur at any time.

D. Assuming that the AAO granted to Ameren for the ice storm that shut down Noranda was appropriate and was for lost fixed costs, what legal basis is there for denying recovery of those amounts deferred?

The legal basis for denying recovery of the deferred amount is that recovery is forbidden as retroactive ratemaking, that is, a prospective recovery from ratepayers of a prior loss caused by a mismatch of revenues and expenses. The Missouri Supreme Court has held, "[p]ast expenses are used as a basis for determining what rate is reasonable to be charged in the future in order to avoid further excess profits or future losses, but under the prospective language of the statutes, §§ 393.270(3) and 393.140(5), **they cannot be used to set future rates to recover for past losses due to imperfect matching of rates with expenses."**[367] This question constitutes Issue 4, above, and a more detailed discussion may be found there.

--Kevin A. Thompson.

CONCLUSION

In conclusion, Staff recommends that the Commission grant Ameren Missouri a general rate increase amounting to approximately $94,407,550 and set its ROE at 9.25%, resolving each contested issue as Staff has recommended. In this way, just and reasonable rates will be set and all relevant factors considered, with due regard to the interests of the various parties and to the public interest.

WHEREFORE, on account of all the foregoing, Staff prays that the Commission will issue its findings of fact and conclusions of law, determining just and reasonable rates and charges for Ameren Missouri as recommended by the Staff herein; and granting such other and further relief as is just in the circumstances.

[367] ***UCCM,*** 585 S.W.2d at 59 (emphasis added).

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing was served, either electronically or by hand delivery or by First Class United States Mail, postage prepaid, on this **31st day of March, 2015,** to the parties of record as set out on the official Service List maintained by the Data Center of the Missouri Public Service Commission for this case.

/s/ Kevin A. Thompson