BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Tariff Filings of Union Electric Company d/b/a Ameren Missouri, to Increase Its Revenues for Retail Electric Service.	)))	File No. ER-2014-0258

INITIAL POST-HEARING BRIEF OF AMEREN MISSOURI

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COMES NOW Union Electric Company d/b/a Ameren Missouri ("Company" or "Ameren Missouri"), by and through counsel, and for its Initial Post-Hearing Brief states as follows:

This brief is in two main sections, the first of which addresses the Company's rate request and the proper design of its rates, and other traditional issues that sometimes arise in rate cases. The second part of the brief addresses what is really a "case within a case"; that is, Noranda Aluminum, Inc.'s ("Noranda") request for an unprecedented, large rate subsidy based on its claimed financial need.

PART ONE: AMEREN MISSOURI'S RATE INCREASE AND RATE DESIGN REQUESTS

INTRODUCTION/POLICY

This rate case is primarily driven by the more than $1 billion of investment Ameren Missouri placed in service between the end of the true-up period in the Company's last rate case (July 2012) and the end of the true-up period in this case (December 2014). A myriad of generation, transmission and distribution investments were made, including a new reactor vessel head at the Callaway Energy Center, electrostatic precipitators ("ESPs") on two of the four generating units at the Labadie Energy Center, large and important substations such as the Central Substation and the Martin Luther King Substation in Metropolitan St. Louis, and the state's largest solar generation facility located in O'Fallon. In addition to these capital investments, rate relief is needed to reflect the nearly $90 million of solar rebates paid in accordance with Missouri's Renewable Energy Standard law, to rebase net energy costs, which have continued to rise, to reflect increased expenditures on items like cyber-security and to reflect higher depreciation expense associated with the expected retirement of the Company's Meramec Energy Center by 2022 (instead of 2027, as had been previously assumed). New rates set in this case will also, however, reflect (i.e., be lower by) the very significant non-energy cost related operations and maintenance cost reductions (more than $67 million since our last rate case)[1] Ameren Missouri has been able to achieve, despite cost pressures that always exist, including for things like wages and benefits for the Company's employees.

After changes occurring as the result of the true-up in this case, and compromises reached on several other issues, the Company is seeking an increase in its revenue requirement of approximately $181.2 million, an increase of about 6.7% in total over the rates last set by the Commission approximately two and one-half years ago.[2] Even after the Commission reflects these legitimate investments and other increases in the Company's costs in rates, Ameren Missouri's rates will continue to remain significantly below national, regional and Missouri averages.[3] The Company fully understands that rate increases are unpopular, and has worked very hard to minimize them when and where it can. The reality is that electric utilities across the Country and the state have had to raise rates significantly over the past several years. But customers are getting value for the rates that they pay, as reflected in the significant improvements in the Company's reliability over the past several years. The bottom line is that a rate increase is needed because of the legitimate, normal investments in utility infrastructure the

[1] Ex. 29, p. 2, l. 19-23 (Moehn Surrebuttal).
[2] Approximately $103 million simply reflects rebasing net energy costs. EFIS Item 425.
[3] Ex. 28, p. 11 (Moehn Direct).

Company has made, and by the other legitimate, normal expenditures that the Company has incurred and must continue to incur in order to be able to provide the kind of service its customers have come to expect.

Not only are the Company's rates comparatively low, but it should be noted that the Company works hard to promote affordability where it can. As Ameren Missouri President Michael Moehn testified:

> …Again, as we just had the discussion, …where we can control costs, we are do-- I'm doing absolutely everything I possibly can to make sure the product stays as affordable as possible. And again, I know there was a discussion this morning about the relevance of where our rates are, and 24 percent below the national average, the cheapest investor-owned utility in the state of Missouri. I think it does matter to stay competitive. I am trying do everything I can to make sure we keep this product as affordable as possible, recognizing that I still have an obligation to serve.[4]

In addition to controlling costs the Company makes other significant efforts to help its customers that have the least ability to pay, including initiatives such as Dollar More, participation in LIHEAP and Keeping Current, and by providing energy assistance to military families and not-for-profit organizations.[5] In addition, annually, Ameren Missouri commits tens of millions of dollars to its low-income weatherization programs where entire homes are made over, from top to bottom, so that they are energy efficient and in this case, Ameren Missouri is the first utility in the state to provide a low-income exemption from our Missouri Energy Efficiency Investment Act charges, as allowed by law.

Those that oppose the Company's revised rate increase request and the regulatory mechanisms that remain at issue in this case appear to be attempting to use, or really misuse, this rate case to both deny the Company of its legitimate cost of service and in many instances to

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[4] Tr. p. 198, l. 12 to p. 199, l. 1.
[5] Ex. 28, p. 17, l. 9 to p. 18, l. 8.

severely erode the regulatory framework in the state. Specifically, some opponents are proposing to: eliminate the FAC and make us one of the very few electric utilities in the country without one; substantially change the terms of the FAC by revising the sharing percentage or pulling out transmission charges to render it far less effective; impose an ROE lower than that approved for approximately 99% of all electric utilities over the past 30-plus years; impose, unlike every other state, a retrospective earnings test, which is completely unfair and effectively eliminates the Commission's ability to use an accounting authority order ("AAO") as a regulatory tool, and which eliminates utilities' ability to rely on amortization of deferrals that arose due to extraordinary circumstances, including from legal mandates; selectively pick-and-choose tax positions which fail to reflect Ameren Missouri's tax expenses; and for the first time, set a rate for a customer based on its claimed private financial circumstances rather than the cost incurred to serve it. These out-of-the-mainstream positions, if adopted, would have severe, negative consequences for Ameren Missouri and other Missouri utilities, and ultimately their customers, who depend on reasonable and constructive regulatory policies to promote investment in utility infrastructure and the safe and reliable service Missouri's utilities are expected to provide. The Commission should see these proposals for what they are and summarily reject them.

The Company has been a good steward of the rate increases this Commission has seen fit to grant it, as discussed in Ameren Missouri President Michael Moehn's direct testimony. The Company has invested several billion dollars in its infrastructure in the past several years, including more than $1.5 billion since its last rate case.[6] The reliability of its service has improved by 44 percent since 2006.[7] Sulfur dioxide emissions have been cut almost in half since

[6] Ex. 28, p. 8, l. 22 to p. 9, l. 1.
[7] *Id.*, p. 7.

2006, and further air emission reductions are occurring because of investments like the ESPs at Labadie.[8] The availability of our power plants remains high, and the Company's Callaway Energy Center carries the Institute for Nuclear Power Operations highest possible rating.[9]

The facts addressed above are important to keep in mind as the Commission decides the remaining contested issues in this case, which are addressed in detail below.

CONTESTED ISSUES

I. SOLAR REBATES

In 2008, Missouri voters enacted the Missouri Renewable Energy Standard ("RES"), which is codified at §§ 393.1020 – 1030, RSMo.[10] Section 393.1030.3 mandates that electric utilities pay solar rebates to qualifying customers in an amount per watt specified in the statute.[11] Other provisions of the RES impose a renewable portfolio standard which requires (in addition to the mandated solar rebates) that electric utilities generate or purchase specified percentages of the energy sold to customers from renewable energy resources (or purchase equivalent amounts of renewable energy credits ("RECs")). There is, however, one limit on the electric utilities' obligation to pay solar rebates and to otherwise meet the renewable energy resource portfolio requirements – a 1% retail rate impact ("RRI") limit provided for in the RES. The RRI limit means that if the payment of solar rebates, plus meeting the portfolio requirement, would cause the electric utilities' rates to be higher by more than 1%, as compared to what the rates would have been without paying solar rebates and meeting the portfolio requirements, the utility must

[8] *Id.*, p. 8, l. 3-10.
[9] *Id.*, p. 8, l. 19-21.
[10] Unless otherwise specified, statutory references are to the Revised Statutes of Missouri ("RSMo.") (Cum. Supp. 2013).
[11] The amount per watt began at $2 per watt, became $1.50 per watt on July 1, 2014, and will become $1 per watt on July 1, 2015, with the solar rebates to continue to be reduced each year until they are entirely eliminated in 2020. § 393.1030.3.

scale back its solar rebate payments and/or its use of renewable energy resources so that the RRI limit does not exceed 1%.

In recognition of the 1% RRI limit, §393.1030.3 provides that if an electric utility determines it will reach the 1% RRI limit in a given calendar year, it must make a filing with the Commission seeking permission to suspend the electric utility's solar rebate tariff, which in turn would result in a suspension of further solar rebate payments during that calendar year. Ameren Missouri made such a filing in 2013 (File No. ET-2014-0085).

Shortly before the scheduled rebate suspension case hearings, Ameren Missouri, together with the Staff, the Office of the Public Counsel ("OPC"), the solar industry's Missouri trade association (the Missouri Solar Energy Industries Association, or "MOSEIA"), a solar installation company (Brightergy, LLC), a renewable energy advocate group (Earth Island Institute d/b/a Renew Missouri), the Missouri Division of Energy and the Missouri Industrial Energy Consumers ("MIEC") entered into a Stipulation and Agreement (the "SR Stipulation").[12] The SR Stipulation resolved File No. ET-2014-0085 without cessation of solar rebate payments for 2013, and without cessation of solar rebates in subsequent calendar years unless and until a "pool" of solar rebates created by the SR Stipulation was exhausted. No party opposed the SR Stipulation, rendering it unanimous,[13] and it was approved by Commission Order dated November 13, 2013.[14] Ameren Missouri later filed tariff sheets to reflect the terms of the SR Stipulation and the Commission's Order approving it, and continued to pay solar rebates without interruption in reliance on the SR Stipulation and the Commission's approval.

[12] Ex. 55.
[13] 4 CSR 240-2.115(2)(C).
[14] Ex. 243.

The SR Stipulation and the Commission's Order approving it contain several provisions that are important to the Commission's resolution of the issue raised by MIEC in this case, which are summarized as follows:

- The Signatories agreed that Ameren Missouri would not suspend solar rebate payments in 2013 or beyond unless solar rebate payments starting after July 31, 2012 reached a total of $91.9 million.[15]

- The Signatories agreed that the solar rebate payments "shall be included in a regulatory asset to be considered for recovery in rates after December 31, 2013, in a general rate case."[16]

- The Signatories agreed that if the entire $91.9 million pool had not been paid by the first general rate case occurring after December 31, 2013, then one or more additional regulatory assets would be reflected on Ameren Missouri's books, and the Signatories agreed to a specific true-up mechanism to ensure, in one or more subsequent general rate cases, that customer rates would reflect no more and no less than the actual solar rebates paid.[17]

- Ameren Missouri agreed to give up its right to seek utilization of a Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM"), which under the Commission's RES rules would allow automatic rate adjustments to reflect costs of complying with the RES (including the cost of solar rebates) outside a general rate proceeding, and that instead the solar rebates would only be included in the revenue requirement in a general rate case through a three-year amortization of the sums recorded to the regulatory asset.[18]

- The Signatories agreed "not to object to Ameren Missouri's recovery in retail rates of prudently paid solar rebates" and the additional 10%. They also agreed that "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" and that "'prudently paid' relates only to whether Ameren Missouri paid the proper amount due to an applicant 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" (emphasis added).[19]

[15] Ex. 55, ¶ 7.a.
[16] *Id.*, ¶ 7.d.
[17] *Id.*, ¶¶ 7.d. and ¶ 7.e. The Signatories also agreed that an additional 10% of the sum of solar rebates paid would be recorded to the regulatory assets.
[18] *Id.*, ¶ 7.d.
[19] *Id.*, including n.7.

- The Commission's Order approving the SR Stipulation reflects the Commission's independent finding and conclusion that the "stipulation and agreement [the SR Stipulation] is in the public interest and should be approved."[20]

- The Signatories, including MIEC, agreed that the SR Stipulation was a "binding agreement among the Signatories" and agreed to "cooperate in defending the validity and enforceability of [it] . . . and [its] operation . . . according to its terms."[21]

- The Commission's Order approving the SR Stipulation specifically "approved" it and ordered the Signatories to "comply with the terms" of the SR Stipulation.[22]

- Ameren Missouri also agreed to give priority to "in-state" RECS even though the Commission's RES rules contain no such preference.

Except for MIEC, all Signatories to the SR Stipulation that are also parties to this rate case either affirmatively support (in the case of the Staff[23]), or do not oppose an amortization of the solar rebate regulatory asset in this case, as specifically provided for and contemplated by the SR Stipulation and the Commission's order approving it. MIEC opposes the amortization based solely on its theory that the solar rebates were "already recovered" by so-called "over-earnings," as does CCM.[24] It should be noted that the term "over-earning" (or "under-earning") is a misnomer and, as used in this brief, simply refers to the situation where a utility's raw, per-book earnings are above or below the targeted ROE used to set the revenue requirement in the utility's prior general rate proceeding. As discussed below, and as recognized by the Commission, "over-

[20] Ex. 243.
[21] Ex. 55, ¶ 11.
[22] Ex. 243.
[23] Staff witness John Cassidy, both in the Noranda rate shift case last summer (File No. EC-2014-0224) and in this case, has steadfastly indicated that the SR Stipulation means that one-third of the regulatory asset balance must be included in the Company's revenue requirement in any general rate case where rates are re-set. This is that case.
[24] The deferred solar rebate expenses at issue in this case total $88.1 million (through December 31, 2014) which, together with the 10% adder, brings the total regulatory asset at issue in this case to $96.9 million. Ex. 57. Using the three-year amortization contemplated by the Solar Rebate Stipulation and the Commission's order, the revenue requirement impact in this case is approximately $32.3 million.

or under-earnings" are normal, expected and do not mean the utilities rates were too high or too low, were unjust or unreasonable or produced an inappropriate level of revenues.

A. MIEC's position on the solar rebate issue must be disregarded, and testimony seeking to deny amortization of solar rebates should be stricken.

Ameren Missouri hereby renews its February 23, 2015 *Objection to the Admission of the Testimonies of Greg R. Meyer and James R. Dittmer*, which, along with Ameren Missouri's on-the-record argument thereon, is incorporated herein by this reference. While the Company will not belabor the points here, it restates that the only fair reading of MIEC's position in this case on the solar rebate issue is that MIEC is acting in violation of its binding obligation to Ameren Missouri and the other Signatories, in violation of the Commission's Order requiring that it comply with the SR Stipulation and is collaterally attacking the Commission's Order approving it in violation of §386.550. Consequently, those portions of Mr. Meyer's testimony identified in Ameren Missouri's above-cited *Objection* should be stricken, as should any other testimony given by Mr. Meyer on the solar rebate issue in this case and any argument by MIEC on the solar rebate issue.

Also, for the reasons given in the Company's above-cited *Objection*, the testimony of James R. Dittmer should be stricken because it is clear that but for MIEC's contacts with Mr. Dittmer, and its procurement of Mr. Dittmer's testimony, no such testimony would have been prepared or filed. To allow Mr. Dittmer's testimony into the record is to allow MIEC to do indirectly what it may not do directly. The Company agrees that CCM counsel may *argue* in opposition to an amortization of the solar rebate payments, but he should not be aided by testimony procured in violation of the SR Stipulation.

Insofar as the Regulatory Law Judge has previously overruled the Company's objection, the Company will address the merits of MIEC's and CCM's position, below, but urges the Commission to reconsider the Regulatory Law Judge's ruling and to sustain the objection.

B. MIEC's and CCM's positions are wrong as a matter of law.

MIEC attempts to avoid the SR Stipulation's prohibition against challenging Ameren Missouri's amortization of the solar rebates it paid by claiming that it is not challenging the "recovery" of the solar rebates. MIEC had no choice but to claim that it is not challenging "recovery," for it had specifically agreed that it would not oppose "recovery" on any ground other than imprudence, which neither it nor any other party claims. Consequently, MIEC came up with the theory that the solar rebates "have already been recovered" and that to allow an amortization in this case would allow Ameren Missouri a "double-recovery" or "another recovery" of the solar rebates Ameren Missouri has paid.[25] Predictably, CCM makes the same argument, that is, after MIEC explained the argument to Mr. Dittmer and procured him as a witness.

MIEC and CCM's theory depends entirely on whether past rates paid by the Company's customers – indeed past, lawfully-established rates that happened to produce per book returns above the ROE targeted when rates were last set in December 2012 – can somehow be retroactively taken from the Company and treated as if they actually reflect a payment by those customers of the solar rebate costs. They cannot.

First, the entire premise of MIEC's and CCM's position is flawed because it is simply not true that actual per book earnings above the earnings that would have been produced had the utility earned exactly the target ROE used to last determine the utility's revenue requirement means that the utility has somehow received "extra funds" that the Commission can or should

[25] *MIEC's Suggestions in Opposition to Ameren Missouri's Motion to Strike*, p. 5 at ¶ 9.

then treat as available to "pay for" particular past expenses incurred by the utility – here, the solar rebate expenses deferred to a regulatory asset pursuant to the AAO granted by the Commission. This is because under Missouri law, a return authorized by the Commission when it sets rates is simply a target, and any earnings that are actually realized by the utility above (or below) that target are the property of the utility. ***Straube v. Bowling Green Gas Co.***, 227 S.W.2d 666, 671 (Mo. 1950) ("When the established rate of a utility has been followed, the amount so collected becomes the property of the utility, of which it cannot be deprived by either legislative or judicial action without violating the due process provisions of the state and federal constitutions."). Put another way, an authorized return is not a ceiling on what a utility can earn, nor is it a floor. *Id.* ("No maximum or minimum return was determined when the rate was established."). MIEC and CCM, however, are treating the targeted ROE as a ceiling by arguing if the earnings exceed the target they can be seized to "pay for" the expenses deferred, with Commission authority, to the regulatory asset.

Second, by arguing that customers' payment of rates mean that the Company has "already recovered" a particular cost, MIEC and CCM act as though customers *actually paid* the solar rebate costs incurred by the Company. The law is contrary, because customers do not pay costs, but rather, customers pay only for the service being provided to them. ***State ex rel. Empire Dist. Electric Co. v. Public Service Comm'n***, 100 S.W.2d 509, 512 (Mo. 1936), *quoting* ***Board of Public Utility Comrs. v. New York Telephone Company***, 271 U.S. 23, 70 (1926) ("The revenue paid by the customers for service belongs to the company. The amount, if any, remaining after paying taxes and operating expenses, including the expense of depreciation, is the company's compensation for the use of its property. * * * Customers pay for service, not for the property used to render it. Their payments are not contributions to depreciation *or other* *operating expenses*, or to capital of the company. By paying bills for service they do not acquire any interest, legal or equitable, in the property used for their convenience or in the funds of the company." (emphasis added).

The bottom line is that the practical effect of accepting MIEC's and CCM's theory would be to treat the targeted ROE as a ceiling (without a floor) and to confiscate the earnings above the ceiling and to then earmark those past earnings to a particular expense. Doing so would be to act as if customers wrote a check to the solar system owners for the solar rebates, when in fact the Company is the one that wrote the checks as required by law, including as required by the SR Stipulation. Doing so would also be at war with both of the legal principles cited above. The Company's past earnings were what they were, and the funds that produced those earnings belong to the Company. In exchange for the rates they paid, customers got exactly what they paid for – electric service – and customers received that service at the lawful rates set by the Commission effective January, 2, 2013. The Company hasn't "already recovered" anything. To the contrary, the Company has simply received revenues generated by the rates paid to it for the electric service it provided. Customers have not paid even one dollar of solar rebate costs, or for any other expense, whether those expenses are for wages of the Company's employees, the Company's materials costs, depreciation expense, or any other cost incurred by the Company.

Commissioner questions during the evidentiary hearings made clear the Commission understands this well.[26] For example, the Chairman posed a hypothetical where the utility had eight different deferrals of $25 million each (totaling $200 million) but "over-earnings" of $100 million. Even MIEC could not say which of the deferred costs had "already been recovered."[27] As Ameren Missouri witness Laura Moore testified, the rate revenues the Company receives are

[26] Tr. p. 467, l. 16 to p. 468, l. 4.
[27] *Id.*

fungible.[28] It is entirely understandable that MIEC cannot say which of the deferred costs were "already recovered" because none of those deferrals in the Chairman's hypothetical could have already been recovered by the $100 million, because it is service, not costs, that are paid for by customers, and because utilities earn what they earn between rate cases. While it is true that there were some "over-earnings" in 2013 – equating to just 53 basis points above the target – and that there were some "under-earnings" in 2014 – equating to nine basis points below the target – as discussed below, over time there have been other periods of both "under- and over-earnings," which balance each other over the long term. That is normal; indeed it would be abnormal if it did not occur. But it has no bearing whatsoever on the propriety of reflecting an amortization of the solar rebate costs in the revenue requirement in this case, just as was agreed-upon in the SR Stipulation and as was contemplated by the Commission's Order approving it.

C. Adoption of MIEC's and CCM's position would be a bad policy decision.

For the reasons discussed above, MIEC and CCM should not be allowed to perform the end-run that is being attempted around the SR Stipulation. There are no claims of imprudence, and it is clear that absent imprudence, the Signatories (and we believe the Commission itself, as indicated by its independent finding that the SR Stipulation was in the public interest together with its longstanding treatment of Commission-authorized deferrals) intended that the solar rebate costs be included in the revenue requirement through a three-year amortization.

Mr. Reed summarized a number of the policy problems with their position, many of which we will address in more detail below, as follows:

> I take issue with Mr. Meyer's view of "good" and "bad" regulatory policy. Those views are identical to those he presented in the Noranda earnings complaint case (File No. EC-2014-0223) and have already been ruled upon and rejected by this Commission on the basis of sound ratemaking principles. Mr. Meyer fails to acknowledge that the regulatory assets that he proposes to disallow represent

[28] Tr. p. 510, l. 15 to p. 511, l. 4 [sic].

deferrals that were authorized by the Commission, and are prudently incurred costs carried out in the provision of utility service for which the utility is entitled to a reasonable opportunity for recovery. Further, he fails to acknowledge that the accounting criteria for booking regulatory assets is based on regulatory authority to capitalize the asset in the first place. To disregard this regulatory authority and propose to arbitrarily write-off these regulatory assets, despite management's expectation of cost recovery, would call into question the entirety of Ameren Missouri's asset value.

The analysis Mr. Meyer presents is clearly flawed. It suffers from the same shortcomings as the Commission found in the Noranda Aluminum earnings complaint case, *i.e.* that book earnings could not be compared directly to an authorized return, due to factors such as weather, etc. which may have a material impact on those numbers. Further, the impact of his proposals would not be limited to the amortization amounts that Ameren Missouri has proposed for inclusion in the test year revenue requirement, but in some cases he proposes to eliminate the regulatory asset balance - a much larger adjustment than one period's amortization expense. Lastly, it is widely recognized that utilities can and will achieve periods of earnings that are above and below the cost of equity target that was used to set its rates, and that this target is neither a ceiling nor a floor on utility earnings. Mr. Meyer's analysis is completely one-sided and does not acknowledge the 5-year period of consistent and material "underearning" that occurred at Ameren Missouri from 2007-2012. It also fails to acknowledge the disconnect between raw surveillance reports and a utility's normalized earnings as reflected in its revenue requirement at a given point in time. The Commission recognized at the time of the Company's last rate case that even though its raw surveillance reports showed "overearnings," in fact during the same period, the Company's revenue requirement was too low by $266 million.[29]

i. <u>The Company reasonably relied upon the SR Stipulation and the Commission's Order approving it.</u>

The SR Stipulation was agreed-upon and approved against the backdrop of the state's adoption of a policy that encourages the use of renewable energy resources, against the backdrop of mandated utility payments for solar rebates (no matter how economic (or uneconomic) the solar systems they facilitate may be), and against the backdrop of Commission rules that provide for the inclusion of RES costs in utility revenue requirements, including solar rebates, and indeed that contemplate the ability to make specific rate adjustments outside of general rate cases for such costs through the use of a RESRAM. The Company, in good faith, gave up its right to use a

[29] Ex. 40, p. 8, l. 3 to p. 9, l. 11 (Reed Rebuttal).

RESRAM and gave up its right to insist that the Commission rule on its contention that it would reach the 1% RRI limitation in order to resolve the solar rebate case. Also, the Company agreed to create an uninterrupted pool of solar rebates – $91.9 million worth – and to pay them according to law per the SR Stipulation and the Commission's Order approving it. The Company has fully lived up to its agreements, and the Company has only charged the lawful rates this Commission has set. There is no question but that the Company reasonably relied upon that Stipulation and Order – and the Commission's longstanding treatment of deferred sums in rate cases (that is, the Commission's consistent inclusion of deferred sums in the revenue requirement in those rate cases) – in deferring the solar rebate costs on its books. As noted, it is not only the Company who believed that when a rate case came along, one-third of the solar rebate regulatory asset balance would be reflected in its revenue requirement. The Staff has the same expectation.

ii. Denying amortization of the deferred sums will effectively eliminate the Commission's ability to utilize accounting authority orders to allow deferrals when the Commission determines it is appropriate to do so.

MIEC and CCM are advocating a retrospective earnings test on amortization of sums that were properly deferred with specific Commission authorization, meaning that the Commission itself determined that the sums were of a nature that justified that they be deferred. As explained by Ameren Missouri witnesses Laura Moore and John Reed, such an earnings test would entirely undermine the Commission's ability to utilize accounting authority to defer extraordinary costs where it believed it appropriate to do so. This is because under applicable accounting standards, utility management must have an order from the Commission authorizing the deferral and must be able to conclude (based on such an order and the regulatory commission's policies, practices and history) that it is probable that the deferred sums will in fact be reflected in the revenue requirement used to set rates in a future rate case. "Probable" in this context is far more than "more likely than not," and in fact it requires a probability of 75% or higher.[30] An earnings test is inherently at war with the accounting standards that dictate if the deferral can actually occur.

As Ms. Moore put it, "if we had some sort of earnings standard or something where we had to go back and look, we would never be able to actually defer those costs on our books."[31] Mr. Reed testified similarly, stating that adoption of the earnings test approach advocated by MIEC and CCM "even for one rate case, would seriously undermine the 'probability of recovery' requirement for creating a regulatory asset and would call into question the value of all of the utility's regulatory assets and the reliability of the Commission's authorizations for the creation of regulatory assets."[32]

And make no mistake – application of such an earnings test using the raw per-book surveillance results MIEC and CCM rely upon would not just reduce the revenue requirement in this case by more than $32 million, but it would require the Company to *completely reverse the deferrals the Commission authorized it to make, which would in turn <u>result in a reduction in the Company's 2015 earnings of nearly $97 million, or approximately 160 basis points in 2015 alone</u>.*[33] In fact, given that no one can know with high probability what future earnings may be (calling into serious question the ability to reach or to continue to reach the high "probability of recovery" standard discussed earlier), such a decision could, as Mr. Reed also indicated, call into question other regulatory assets currently on the Company's books that have not, to date, been

[30] Tr. p. 511, l. 13 to p. 512, l. 25.
[31] *Id.*, p. 512, l. 18-21.
[32] Ex. 40, p. 12, l. 19-22.
[33] According to the Staff's True-Up Reconciliation (EFIS Item 398), the 115 basis point difference between the Staff's midpoint ROE recommendation and the Company's ROE recommendation is approximately $69.1 million, meaning a basis point of ROE equates to approximately $600,000 of earnings. A write-off of the entire $96 million regulatory asset would therefore equal approximately 160-basis points ($96 million/$600,000). In fact, the write-off would likely be even greater as it would also have to reflect additional solar rebates paid since December 31, 2014, since application of a retrospective earnings test would call into question the ability to defer all of the solar rebate expenses, regardless of when incurred.

challenged and remove the use of a regulatory asset as a tool in the Commission's regulatory toolbox:

> If the Commission were to endorse Mr. Dittmer's [or Mr. Meyer's identical] view and write-off the full amount of the regulatory asset balance (approximately $100 million) to current year earnings, it would send a message to Ameren Missouri's accountants and the financial community that there are unpredictable and punitive strings attached to the booking of regulatory assets, such as solar rebate costs, and that recovery in fact is neither probable, nor still supported by ratemaking practice; instead, recovery would be contingent on the past earnings of the company. Going forward, none of Ameren Missouri's regulatory assets would meet the accounting criteria for capitalization which most definitely would have a bearing on investors' confidence in this Commission's willingness to allow recovery of prudently incurred costs. This would effectively remove from the Commission's toolbox one of the regulatory tools that it has long used in regulating the rates of the utilities under its jurisdiction.[34]

iii. <u>Raw per-book surveillances results should not be utilized in the manner advocated by MIEC and CCM.</u>

The Commission should not for any reason force the Company to bear an approximately 160 basis point earnings reduction in 2015 arising from the payment of the solar rebates (or to have its other regulatory assets called into question generally), but it certainly should not do so in reliance on raw, per-book surveillance results that tell us very little about the justness and reasonableness of the rates the Company has been lawfully charging since the Commission set those rates a little more than two years ago. As Staff witness John Cassidy put it, "per book results have limited value."[35] Mr. Cassidy also agreed that it is normal for actual results to vary from the target, and that just because that happens does not mean that the rates in effect are unjust and unreasonable.[36] As Mr. Reed pointed out, the Commission also recognizes the limitations of per-book surveillance results, having recently stated that "it is important to understand that the earnings level recorded in the surveillance reports are actual per book

[34] Ex. 41, p. 18, l. 18 to p. 19, l. 8 (Reed Surrebuttal).
[35] Tr. p. 536, l. 9-10.
[36] Tr. p. 585, l. 17-24.

earnings of the utility and cannot be compared directly to an authorized return on equity to determine whether or not a utility is overearning."[37] If, as Mr. Cassidy testified, such results have "limited value" and if, as the Commission recognizes, they can't be compared directly to the authorized or targeted return, then it necessarily follows that surveillance results should not be used to in effect retroactively take legitimately-received earnings away from the Company, as MIEC and CCM in effect propose here.

Formulaic use of raw per-book surveillance results as suggested by MIEC and CCM can also be extremely misleading, as illustrated by some of the "over-earnings" MIEC relies upon and by the visual picture some of Mr. Meyer's charts were apparently intended to create.[38] For example, many of the periods depicted in Mr. Meyer's charts (which counsel for MIEC and CCM both displayed prominently during the hearings) are impacted by earnings levels in 2012 when some might argue that there were per-book earnings that were very significantly above the targeted ROEs at the time. However, we know that while these 2012 "over-earnings" were occurring, on a regulated basis the Company's rates were in fact *too low* (meaning its "regulated returns" were too low even though raw surveillance results showed earnings above the target), and we know this because we have full cost of service studies for a trued-up test period for the 12 months ending July 2012. Indeed, at that time, the Staff, the Company and ultimately the Commission agreed that in fact the rates that were producing those per book "over-earnings" were lower than they needed to be as evidenced by the significant revenue *deficiency* the cost of service studies showed. Staff's cost of service study showed a non-energy cost related

[37] Ex. 40, l. 5-8 (quoting *Report and Order*, File No. EC-2014-0223); Tr. p. 548, l. 19-24.
[38] The math in Mr. Meyer's charts is literally accurate, in the sense that each rolling 12-month period shows the "over-earnings" for that 12-month period. However, the pictures painted by the charts appear to be intended to make it appear that there is something unjust about the earnings, and that during the period the solar rebates were deferred, the "over-earnings" were extreme or perhaps unusual, as Mr. Meyer contended in File No. EC-2014-0223. The facts are contrary, however. We now know that for 2014 there were under-earnings, and that even for 2013 the full year's earnings were somewhat, but not significantly, above the targeted ROE.

deficiency of approximately $210 million (at Staff's recommended target ROE of 9.0%),[39] and the Commission authorized a non-energy/non-MEEIA program cost related increase of more than $70 million and a total rate increase of $260.2 million, using a target ROE of 9.8%.[40] And while it is true that Mr. Meyer did not have data past September 2014, the suggestion one might take away from his 2014 chart, as far as it went, was that 2014 earnings might end up far above the targeted ROE, when in fact 2014 earnings ended up below the target.[41]

As the information in Mr. Reed's surrebuttal testimony indicates, over the past eight years, per book surveillance results have shown "under-earnings" in six of the eight years and "over-earnings" twice.[42] The degree to which actual earnings were below the targeted earnings has been significantly greater than the degree to which actual earnings have exceeded the target, and those below-the-target earnings have persisted for longer periods of time, and even during periods of "over-earnings," revenue deficiencies have been found by the Commission when the proper ratemaking adjustments needed to truly judge the justness and reasonableness of rates were accounted for. As noted, the Commission recognizes the risk of putting too much stock in these surveillance results, having pointed out in its *Report and Order* in File No. EC-2014-0223 that one cannot compare them directly to the targeted ROE and then draw the conclusion that there are "over-earnings." In that case, the Commission also rejected attempts (also sponsored by Mr. Meyer) to justify a rate reduction based essentially on per book surveillance results, albeit results to which a limited set of adjustments had been made.

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[39] *Staff Reconciliation*, EFIS Item 363, File No. ER-2012-0166.
[40] *Report and Order*, File No. ER-2012-0166.
[41] The point is that the surveillance results should never be used as MIEC and CCM seek to use them; that is, to dollar-for-dollar offset or cancel Commission-authorized and legitimate cost deferrals which in turn created Commission-authorized regulatory assets.
[42] Ex. 41, and in particular, p. 13, l. 9 to p. 16, l. 22. Had Mr. Reed had 2014 data, one would see that bar in Figure 1 once again below the targeted line for 2014.

iv. <u>The Commission has never done what it is being asked to do here.</u>

As noted earlier, the Company's research reveals that the Commission has never refused to include a properly deferred sum in the revenue requirement through an amortization of the balance of the deferral except in cases of miscalculation or imprudence – it has certainly never done so based on past, per-book earnings, although such an argument has been made before.[43]

For example, Mr. Dittmer, in Kansas City Power & Light Company's 2006 rate case, claimed that past "over-earnings" should be used as the basis to deny amortization of deferred sums in the revenue requirement, but the Commission rejected the argument (the same argument being made here), stating as follows:

> The United States Department of Energy (DOE) argues that KCPL has *already recovered* those costs [deferred storm costs] in rates, and that, therefore, the Commission should disallow this expense. According to DOE witness Dittmer, KCPL has recovered those costs due to its robust, if not excessive, return on equity during the ice storm amortization period.
>
> The Commission finds that the competent and substantial evidence supports KCPL's position, and finds this issue in favor of KCPL. DOE complains that KCPL has already recovered those [*93] costs in rates. However, DOE witness Dittmer testified that he was unaware of any Staff or Commission action to reduce rates from 2002 to now because of overearnings, which would include the recovery of ice storm costs from ratepayers. Regardless of KCPL's prior earnings, the Commission gave KCPL an accounting authority order to defer and amortize its ice storm costs through January 31, 2007, which includes the test year in this case.[44]

As Mr. Reed points out, the Commission has also rejected the same argument in other cases, including in *Re Missouri Public Service*, Case No. ER-93-37 (1994), where in rejecting the same argument that is being made here, the Commission stated that it "finds unpersuasive the

[43] Staff Counsel Thompson indicated, in response to a Commissioner question, that he had no reason to doubt the accuracy of this statement. Tr. p. 94, l. 4-11. Mr. Reed, who has longstanding and national experience in regulatory and ratemaking matters, also testified that his firm specifically researched the matter and found no instances where a utility commission had refused to amortize a deferred sum except in cases of imprudence, unreasonableness of the cost or some ineligibility from inclusion under the terms of the agreed-upon deferral mechanism. Ex. 40, p. 16, l. 4-10.

[44] Commission *Report and Order* in File No. ER-2006-0314, *quoted* in Mr. Reed's surrebuttal testimony, Ex. 41, at p. 11, l. 1-15 (emphasis added).

contention of Staff/Public Counsel that these costs have *already been recovered* in rates." (emphasis added).[45]

Not only has this Commission never rejected amortization of regulatory assets based on past earnings levels, but research indicates that no other state regulatory commission has done so either.[46]

In summary, Ameren Missouri charged the rates it was authorized to charge and its earnings have been below and above, and now for calendar year 2014, earnings have again been below, the targeted ROE used to set past revenue requirements upon which rates were based. The Company's earnings belong to it and, just as there was no floor when those earnings were below the target, there should be no ceiling when the earnings were above the target. Retroactively attempting to take past earnings away under the guise of claiming that those earnings "paid for" or "already recovered" deferred costs is tantamount to imposing such a ceiling. And if that were policy in Missouri, the efficacy of AAOs would be called into serious question. MIEC's and CCM's attempt to deny amortization of the solar rebate expenses should be denied.

II. OTHER REGULATORY ASSETS

MIEC (this time by itself) also seeks to rely on "over-earnings" reflected in past surveillance results to deny an amortization of sums properly deferred for two other items – a flood study at the Callaway Energy Center mandated by the Nuclear Regulatory Commission ("NRC") because of the Fukushima disaster, and energy efficiency costs deferred pursuant to prior Commission orders also previously included in past rate case revenue requirements.[47]

[45] Cited and quoted in Mr. Reed's surrebuttal testimony, Ex. 41, at p. 11, l. 16-20 (emphasis added).
[46] Ex. 40, p. 16, l. 17-18.
[47] Tr. p. 508, l. 17 to p. 509, l. 4. The deferred Fukushima sums total approximately $939,000, to be amortized over ten years (revenue requirement impact of $93,900), and amount remaining on the deferral for the energy expenses is

With regard to the flood study costs, Staff witness Cassidy confirmed that the Company has properly accounted for (in this case deferred) the expenses incurred for the flood study in accordance with Uniform System of Accounts Account ("USoA") No. 182.2.[48] Ameren Missouri witness Moore confirmed that the study was mandated by the NRC, and Mr. Cassidy indicated that the Staff's treatment of the costs was viewed in light of the mandated nature of them.[49]

With regard to the energy efficiency costs, Ameren Missouri witness Moore confirmed that in past rate cases the then-unamortized balance had also been included in the determination of the revenue requirement through an amortization, as requested here.[50] Mr. Cassidy elaborated on Ms. Moore's statements, noting that the Staff's (and the Company's) treatment of the energy efficiency deferrals in this case is consistent with past practice (inclusion in the revenue requirement through a 6-year amortization) and is also in line with the state policy of encouraging the reflection of energy efficiency costs in setting rates.[51]

Imposing an earnings test on these amortizations suffers from the same legal and policy concerns expressed above and, consequently, MIEC's attempt to deny an amortization of these properly deferred sums should be rejected.

III. NORANDA AAO

The facts on this issue are not in dispute.[52] Noranda's aluminum smelter lost power in 2009 when a major ice storm downed the Associated Electric Cooperative, Inc. transmission

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approximately $3.5 million, to be amortized over six years (revenue requirement impact of approximately $580,000).

[48] Tr. p. 543. l. 4-16. Account No. 182.2, which is an asset or balance sheet account, provides that it "shall include: (1) Nonrecurring costs of studies and analyses mandated by regulatory bodies related to plants in service, transferred from account 183, Preliminary Survey and Investigation Charges, and not resulting in construction." 18 C.F.R. Pt. 101.

[49] Tr. p. 509, l. 5-13; p. 599, l. 16 to p. 600, l. 2.

[50] Tr. p. 508, l. 18 to p. 509, l. 4.

[51] Tr. p. 600, l. 3-22.

[52] The material facts are recited in the Commission's November 26, 2013 *Report and Order* granting accounting authority (Ex. 3, Schedule LMB-R8, Barnes Rebuttal), as well as in the Court of Appeals, Western District's

lines that deliver power to the smelter. Due to the sudden interruption in power supply, molten aluminum "froze" in the pot lines at the smelter, and had to be jack-hammered out. As a consequence, Noranda's operations (and electricity consumption) did not return to normal until about 14 months later. Because of the ice storm, Ameren Missouri was deprived of tens of millions of dollars of retail revenues from Noranda that would have let Ameren Missouri cover the allocation of fixed costs to Noranda's rate class, which occurred as part of the rate design phase of the Company's 2008-2009 rate case, decided literally hours before the ice storm hit. After being told by the Commission that there was simply no time to address the issue in its then-pending rate case,[53] the Company sought to mitigate the financial impact of the ice storm by entering into two partial requirements contracts, one with AEP Operating Companies ("AEP") and one with Wabash Valley Power Association ("Wabash"). The Company believed that entering into those transactions would keep both the Company and its customers in the same position that they would have been in if there had been no ice storm because the Company believed that such requirements contracts were excluded from the FAC pursuant to an exception in the definition of off-system sales for full or partial requirements sales contained in the Company's tariff. Staff, OPC and MIEC disagreed and, ultimately, about three years after the ice storm occurred, so did the Commission and the Missouri Court of Appeals, Western District.[54]

Shortly after the Commission's decision, the Company requested that the Commission grant it accounting authority to defer the fixed costs which had been allocated to Noranda's rate

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January 13, 2015 Memorandum Providing Reasons for Order Affirming Judgment Under Rule 84.16(B), which is attached to Ex. 3, Schedule LMB-R9. Ms. Barnes' Rebuttal Testimony also recounts additional details about the ice storm and the chain of events that led to the November 26, 2013 *Report and Order* – see pages 60-64.

[53] The rate case had been decided in late January 2009, the day before the ice storm began, but rates were not to take effect until March 1, 2009.

[54] ***Public Serv. Comm'n v. Office of Pub. Counsel (In re Union Elec. Co.)***, 2015 Mo. App. LEXIS 28 (Mo. App. W.D. 2015).

class, which amounted to approximately $36 million or 8.5% of Ameren Missouri's net income. Staff, OPC and MIEC argued that the allocated fixed costs were in fact lost or ungenerated revenues and contended, among other reasons, that accounting authority was unavailable to defer lost revenues. In November 2013, the Commission disagreed with the Staff, OPC and MIEC and issued an AAO, concluding that "[r]evenue not collected by a utility to recover its fixed costs, under some circumstances, is an 'item' that may be deferred and considered for later ratemaking."[55] On January 13, 2015, the Court of Appeals, Western District, affirmed the Noranda AAO. Subsequently, OPC and MIEC sought rehearing and/or transfer, which the Court of Appeals denied. On March 17, 2015, OPC and MIEC then asked the Missouri Supreme Court to grant transfer. Their request for transfer is pending. As the Commission knows, granting transfer is entirely discretionary on the Court's part, and the overwhelming majority of transfer requests are denied.

When it granted accounting authority, the Commission made several determinations, all of which are again being challenged now. As noted, it determined that the sums were an "item" that could be deferred consistent with the USoA. The Commission rejected the contention that lost or ungenerated revenues could not be deferred consistent with the USoA, and cited to other instances where in fact it had allowed deferrals of lost revenues. Specifically, the Commission cited the adoption of the Cold Weather Rule and the Missouri Energy Efficiency Investment Act which permitted the deferral of unrecovered revenues. The Commission found unpersuasive Staff's, OPC's and MIEC's arguments to the effect that the Company had waited too long to ask for the AAO, and that the timing of the request somehow failed to comport with the USoA. The Commission also specifically rejected the contention that granting the AAO would constitute

[55] *Report and Order,* File No. EU-2012-0027 Conclusion of Law No. 3. This *Report and Order* is hereinafter referred to as the "Noranda AAO."

illegal retroactive ratemaking. Finally, the Commission specifically determined that the sums at issue were extraordinary and thus appropriate for deferral. This is the first rate case that has occurred since the Noranda AAO was issued in late 2013, and so it is the appropriate forum for Ameren Missouri to seek recovery of these items.

A. Allowing an amortization of the deferred sums in this case would not constitute retroactive ratemaking.

As MIEC counsel conceded during the evidentiary hearings, MIEC opposes deferrals.[56] MIEC claims they are outright illegal, but concedes that not all court decisions agree.[57] Staff opposes this particular deferral. OPC often opposes deferrals. MIEC and its members have consistently opposed deferrals (as has OPC), arguing for years that deferrals in fact do constitute retroactive ratemaking, even though the courts have repeatedly rejected those arguments. For example, in the appeal of Ameren Missouri's 2008 rate case (File No. ER-2008-0318), MIEC member Noranda (and OPC) claimed that including an amortization of deferred vegetation management and infrastructure inspection costs in the revenue requirement constituted retroactive ratemaking. More specifically, the claim was that "the amortization of past expenses constitutes unlawful and unreasonable retroactive ratemaking."[58] Noranda and OPC then, as MIEC and OPC (and this time, Staff) do now, relied heavily on the *UCCM*[59] case, which MIEC referred to repeatedly during the evidentiary hearings in this case. The Court of Appeals rejected the contention that allowing an amortization of deferred sums constituted retroactive ratemaking. In doing so, it reviewed other decisions that had also addressed the same question, starting with

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[56] Tr. p. 693, l. 4-7.
[57] Tr. p. 693, l. 8-13; p. 694, 19-21. MIEC would almost certainly say the Supreme Court's *UCCM* decision proves its point. As discussed below, every AAO-related decision since *UCCM* was decided rejects MIEC's position, and when the argument has been made to the Supreme Court, the Supreme Court has declined to take it up.
[58] ***State ex rel. Noranda Aluminum, Inc. v. Pub. Serv. Comm'n***, 356 S.W.3d 293, (Mo. App. S.D. 2011) [*citing* Appellants' Brief].
[59] ***State ex. rel. Utility Consumers Council of Missouri, Inc. v. Pub. Serv. Comm'n***, 585 S.W.2d 41 (*Mo. banc* 1979).

State ex rel. AG Processing v. Public Serv. Comm'n, 340 S.W.3d 146, 148 (Mo. App. W.D. 2011). In particular, the Court of Appeals pointed to the fact that when an amortization of a deferred sum is included in a rate case revenue requirement, the resulting rate impact is prospective only:

> An additional consideration supports our rejection of the [a]ppellants' retroactive ratemaking argument: [the utility's] rate adjustment applies only prospectively, to electrical service to be provided to customers *after* Commission approval of the rate adjustment. The rate adjustment does not modify or recalculate the rate to be charged for electricity provided to customers *before* the rate adjustment was approved. In prior cases, this Court has rejected claims that measures to recoup previously incurred costs constitute retroactive ratemaking, when the recoupment measures operate prospectively, and do not alter the cost of utility services previously provided to consumers. *State ex rel. Mo. Gas Energy v. Pub. Serv. Comm'n,* 210 S.W.3d 330, 336 (Mo.App. W.D.2006) ("This is not retroactive ratemaking, because the past rates are not being changed so that more money can be collected from services that have already been provided; instead, the past costs are being considered to set rates to be charged in the future."); *State ex rel. Midwest Gas Users' Ass'n v. Pub. Serv. Comm'n,* 976 S.W.2d 470, 481 (Mo.App. W.D.1998) ("The adjustments permitted under [the adjustment clauses] are applied only to future customers on future bills. The companies are not allowed to adjust the amount charged to past customers either up or down.").

Precisely the same principles enunciated by the Court of Appeals in ***A.G. Processing, Mo. Gas Energy*** and ***Midwest Gas Users' Ass'n*** apply here. In this case, as in those cases, no past rate has been or will be changed. All that will occur is that an amortization of the sums deferred pursuant to the Noranda AAO will be included in the revenue requirement in this case. That revenue requirement will then be used to set new rates, to be applied *prospectively* only. The Court of Appeals has repeatedly rejected the argument MIEC is again making in this case. Indeed, while it is true that the Missouri Supreme Court has never directly taken up the argument since *UCCM* was decided, it has been afforded the opportunity to do so and has allowed this series of Court of Appeals' decisions to stand. For example, in Noranda and OPC's *Application for Transfer* filed in the Missouri Supreme Court, Case No. SC92192 (which was denied on

January 31, 2012), Noranda and OPC argued that allowing an amortization of the vegetation management and infrastructure investment costs deferrals violated *UCCM* on the grounds that the amortization constituted illegal retroactive ratemaking. They argue now that allowing amortization of the deferred sums at issue here would constitute illegal retroactive ratemaking. There is no substantive difference between these arguments; the courts have repeatedly rejected them.[60]

B. All of MIEC's, OPC's and Staff's other arguments were already rejected by the Commission.

Arguably, the retroactive ratemaking argument is new to this case because in the AAO case the argument being made was that the mere act of granting the AAO constituted retroactive ratemaking, whereas here the argument is that allowing the amortization in the revenue requirement in this case is retroactive ratemaking. Its newness renders it no more persuasive, for the reasons just given.

However, no credible argument can be made that the other points raised by MIEC, OPC and Staff are any different than those already raised and rejected by the Commission when it issued the AAO. Staff Counsel was quite candid on this point in response to the Chairman's question at hearing:

> **Q. The argument you are making now, that's essentially the argument for why we shouldn't have granted the AAO in the first instance, though?**
> A. We opposed the granting of the AAO, absolutely.
>
> **Q. And that's the argument you made in opposing, that an AAO wasn't the appropriate mechanism to recover lost revenues?**

[60] Staff Counsel also, in this case, is making the retroactive ratemaking argument (although this has not been the Staff's position in the past), but his argument too is directly at odds with these controlling court decisions. *See* Tr. p. 665, l. 22 to p. 666, l. 4, where Staff Counsel argues that only if the deferred sums arise from something that may recur can an AAO be granted and can an amortization be included in the revenue requirement and that otherwise retroactive ratemaking will occur. The cases cited above simply do not stand for such a proposition. Indeed, by their very nature, AAO's only apply when there are extraordinary and non-recurring events.

A. That's true.[61]

The first repeated argument is that Ameren Missouri was untimely in asking for the AAO because it had rate cases after retail revenues were drastically cut when Noranda's plant was curtailed but before the AAO was requested and that, presumably, there were the same kinds of fixed costs not being covered by the Noranda revenues that were allocated to Noranda's rate class in those subsequent rate cases. The Commission already rejected this argument, finding that the AAO opponents made "no persuasive argument supporting a calculation of the deadline for filing an application for an AAO."[62] Until the Commission ruled that the revenues from the AEP and Wabash contracts had to be included in the FAC, there were no financial detriments to Ameren Missouri arising from the ice storm about which a deferral could be sought. That fact was true in the AAO case and it is true now. MIEC, OPC and Staff are simply rehashing the same point here.

The next repeated argument is that the Commission lacks authority to allow a deferral of what MIEC, OPC and Staff have variously referred to as lost or ungenerated revenues. As earlier noted, the Commission already ruled: "revenue not collected" can be an item eligible for deferral. The Commission has granted accounting authority to defer lost revenues in the past, and the courts have upheld those decisions.[63] The Commission recognized this in the Noranda AAO order and rejected the very argument being made again now.

MIEC, OPC and Staff also argue that because Ameren Missouri's earnings at the time were positive – i.e., were $1 or more – then any "fixed costs" that were not covered by the

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[61] Tr. p. 659, l. 8-17. Mr. Thompson went on to agree that by granting the AAO, the Commission had already determined that the sums at issue were abnormal, and by abnormal he meant extraordinary in the accounting sense. Tr. p. 662, l. 1-13.
[62] Noranda AAO, p. 1, n.2.
[63] *See, e.g., Mo. Gas Energy,* 210 S.W.2d at 335-36, cited by the Commission in the November 26, 2013 *Report and Order,* File No. EU-2012-0027 at p. 3, n. 19.

Noranda retail revenues that were not received were in fact covered by those positive earnings. While it is true that the Commission's Noranda AAO order did not expressly discuss this argument, it is also true that the very same argument was made by these same parties in the AAO case and, given the Commission's ruling, it was obviously rejected by the Commission. As Ms. Barnes' testified, if the standard for granting an AAO or later allowing amortization of deferred sums was that the utility had to have zero or negative earnings, AAOs would never, or almost never, be granted.[64]

While undoubtedly the opponents of including these deferrals in the revenue requirement will point out that the Court of Appeals' order upholding the AAO is not an "opinion," as Commissioner Hall noted during the evidentiary hearings, it is difficult to conclude anything other than that the Court of Appeals' order "pretty clearly says that it was lawful and reasonable for the Commission" to approve the AAO.[65] It was, as longstanding case law indicates. Indeed, this is probably why the Court of Appeals issued a memorandum decision, because the courts have already affirmed the Commission's authority to approve the deferrals on many occasions, and there was really no reason to opine on the same points again. It also makes no sense at all for the courts to repeatedly affirm the Commission's authority to approve the deferrals if, as is now being argued, allowing the amortization would in fact be unlawful.

The arguments lodged against including an amortization of the sums allowed for deferral under the Noranda AAO have already been rejected by the Commission or, in the case of the

[64] Ex. 3, p. 67, l. 12-17. While completely irrelevant to the granting of the AAO or to whether it should be reflected in the revenue requirement in this case, this particular deferral is a perfect example of a situation where the lack of a floor below the targeted ROE appears to cause MIEC no concern whatsoever, yet, as discussed earlier, MIEC advocates for imposition of a ceiling. If the relevant time periods related to the Noranda AAO deferral are 2009 to 2010, when Noranda's retail revenues were way down, and if, as MIEC contends, surveillance results were relevant to the treatment of deferred sums, then there would be all the more reason to allow the amortization of the Noranda AAO deferrals now given that the Company's earnings at that time were below the Company's targeted ROE at the time. Ex. 41, Figure 1, p. 14 (showing earnings below the target for both 2009 and 2010).
[65] Tr. p. 687, l. 10-14.

somewhat different retroactive ratemaking argument being made now, are simply wrong as a matter of law. Ameren Missouri could not prevent the ice storm. Ameren Missouri did not act imprudently – no party is claiming it did. Ameren Missouri could not have mitigated the financial impact of the ice storm – and no party is claiming that it could. The Court of Appeals upheld the Noranda AAO. There is simply no reason to fail to include an amortization of the approximately $36 million of deferred sums (over five years, or about $7.2 million per year) in the revenue requirement in this case. MIEC's, Staff's and OPC's opposition to doing so should be rejected.[66]

C. Commissioner Hall's question regarding legal authority and the Noranda AAO.

At the end of the evidentiary hearings, Commissioner Hall requested the parties address four questions, one of which relates to the Noranda AAO. The Noranda AAO question is as follows:

> ***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 above-discussion makes clear the Commission's granting the AAO was absolutely proper, as would be Commission approval of an amortization of the deferred sums in the revenue requirement in this case. The more direct answer to Commissioner Hall's question is as follows: Longstanding Commission practice regarding AAOs and the court decisions that have arisen from it, indicate that there are two legal bases for the Commission to not allow recovery of sums deferred pursuant to an AAO – imprudence and miscalculation. Is it possible that there are other legal bases? Perhaps, but we don't know. This is because there is no law that would indicate

[66] Allowing amortization of the Noranda AAO deferrals is the most appropriate way to account for the impact of the ice storm, but as discussed in Mr. Wills' Surrebuttal Testimony (Ex. 54, pages 4-5), if the amortization were denied at least the impact of the ice storm could be recognized by normalizing Noranda's load in this case based upon the actual 10-year level of that load, including the impact of the ice storm six years ago.

that there are other legal bases because the Commission has never attempted to deny recovery of an approved AAO on any other basis. And for good reason: denying recovery on another basis after it has granted the AAO, even if legally permissible, would reflect poor regulatory policy.

IV. INCOME TAX EXPENSE

MIEC proposes two income tax-related adjustments in this case.[67] The first is a proposal to increase the accumulated deferred income tax ("ADIT") balance by which Ameren Missouri reduces its rate base by approximately $51 million[68] by means of imputing to the Company a smaller net operating loss carryover ("NOLC") than, in fact, it has. The second is a proposal to reduce tax expense to reflect an increase in the Company's Internal Revenue Code section 199 domestic production deduction ("DPD"). This increase is driven mechanically by one of two alternative assertions. The first alternative is that, in computing the DPD, any and all NOLCs available to the Company should be ignored notwithstanding that the tax law *requires* them to be considered. The second alternative is that, for purposes of computing the DPD, again the Company should be treated as having a smaller NOLC than it, in fact, has.[69]

The testimony in this case demonstrates that the Company's treatment of these two items is consistent with the applicable tax law, financial accounting and, most importantly, economic reality. It further demonstrates that MIEC's proposed adjustments comport with none of these. In fact, the primary (if not sole) rationales offered is that these adjustments would, if adopted, reduce rates and that the Commission should evaluate the consolidated group's tax allocation practices as an "affiliate transaction." The first part of the rationale is undeniably true, but as the

[67] While Staff supports both of MIEC's proposals, the testimony of its witness generally limits itself to statements of support. Consequently, the discussion in opposition to MIEC's positions should be understood to also oppose Staff's positions.
[68] This amount represents the federal ADIT effect of MIEC's proposal. There is an additional approximately $7 million impact relating to state ADIT.
[69] This latter assertion employs precisely the same reasoning (and NOLC amounts) as does MIEC's "ADIT" proposal described above. Consequently, the resolution of the issue for one purpose should resolve it for the other purpose as well.

Commission is aware, it cannot simply resolve rate case issues by choosing the position that results in the lowest possible rates. To the contrary, it decides rate case issues based upon the utility's legitimate revenue requirement, comprising an appropriate level of revenues, expenses and rate base determined fairly in accordance with the law; i.e., it sets just and reasonable rates.[70] Indeed, the fact that MIEC's position will produce lower rates is simply irrelevant. The second part of MIEC's rationale is seriously flawed and, we respectfully suggest, unfairly opportunistic. The testimony, when evaluated in that light, supports Ameren Missouri's treatment of these items.

A. Accumulated deferred income taxes.

Ameren Missouri's rates must be set to provide it a reasonable opportunity to recover the cost of the capital it has invested in the assets necessary to provide its regulated service. Most, but not all, of this capital has a cost associated with it and that cost is reflected in the Company's overall weighted cost of capital upon which rates are based. However, one particular type of capital, ADIT, has no cost. This cost-free capital exists largely compliments of Congress. For example, when Congress enacted 100% bonus depreciation towards the end of 2010, with the stroke of a pen, a utility that bought an asset in 2011 became able to claim the entire cost of the asset as a deduction on its income tax return for that year. This had the effect of decreasing its income tax liability in that year, leaving it with more cash.[71] The accountants record this "extra" cash as ADIT. Because the Company (or any taxpayer) only gets to depreciate the cost of a business asset once, claiming 100% bonus depreciation in 2011 necessarily means that it will not be able to claim any additional depreciation deductions with respect to the asset in any later year through the end of that asset's life. The lack of tax deductions in subsequent years will increase

[70] §393.130, RSMo.; ***State ex rel. Wash. Univ. v. Pub. Serv. Comm'n***, 272 S.W. 971, 973 (Mo. 1925) (Fair administration of the PSC law is mandatory. "Fair" means fair to the public and to utility investors).
[71] Tr. p. 349, l. 6-12.

the utility's taxable income and its tax liabilities in those years resulting, over the remaining life of the asset, in the restoration to the government of the "extra" cash it enjoyed in 2011 as a result of claiming bonus depreciation – the ADIT. In short, the benefit of ADIT is a temporary benefit. So ADIT represents incremental cash provided through the tax system, which will be repaid through the tax system without interest.[72]

The amount of ADIT possessed by most utilities is significant – as it is for Ameren Missouri. The cash represented by its ADIT balance is available to the Company to invest in the assets it uses to serve its customers. As with all of the capital the Company invests in the assets it uses to serve its customers, its cost must be factored into the setting of rates. However, the ADIT balance has no cost. The convention used in Missouri to reflect in the rate-setting process the fact that ADIT has no cost is to reduce rate base by the ADIT balance. By that mechanism, rates customers pay are not set based upon a return on the portion of the Company's rate base that is supported by this cost-free cash. Through lower utility rates, customers effectively get the benefit of the interest-free loan the Company has received from Congress.[73]

So the justification – the only justification – that supports reducing a utility's rate base by its ADIT balance is that, to the extent of the reduction, it has cost-free capital available for investment in its operating assets.

There is no dispute as to the actual quantity of ADIT Ameren Missouri possessed at any point in time (including as of the end of the trued-up test year). The Company based its rate base calculation upon precisely that quantity. In other words, its rate base calculation provided

[72] Commissioner Bill Kenney provided a real life example of this when he described the treatment of the Yukon Denali his company purchased in 2003. The company "wrote off" the entire cost of the vehicle in that year. That undoubtedly reduced its taxes. However, having deducted the entire cost in 2003, in the next two years the company could claim no depreciation deductions. Its tax liability in those years was undoubtedly higher than it otherwise would have been. (Tr. p. 355, l. 15 to p. 356, l. 18); Ex. 48, p. 11, l. l6 to p. 13, l. 6 (Warren Rebuttal).
[73] *Id.*, p. 13, l. 8-12.

customers with 100% of the benefit of the cost-free capital it had in its possession.[74] That is the economic reality of its situation. MIEC and Staff are unwilling to accept this reality. Instead, they have proposed to calculate rate base using the higher level of ADIT the Company would have possessed had it filed its income tax returns on a basis upon which it does not file.[75]

The difference between the Company's ADIT calculation and MIEC's relates to the treatment of the Company's NOLC. There is no disagreement regarding the economic consequences of this NOLC or the necessity to reflect its economic consequences in ratemaking.[76] Chairman Kenney put his finger on it when he stated his understanding to be that the effect of an NOLC is to reduce the ADIT otherwise available.[77] The Company's ADIT liability includes the effect of *all* tax deductions, whether or not they actually deferred tax. In those years in which the Company produced an NOLC and there was also a consolidated NOLC, some of the Company's deductions did not yet get used and, therefore, did not defer any tax. Only deductions that defer tax produce cost-free capital. Therefore, consistent with Chairman Kenney's observation, the NOLC must be offset against the ADIT balance to properly reflect the true level of ADIT – *i.e.*, the cost-free capital – the Company actually possesses. This treatment is not in dispute. The only disagreement is over the quantity of the Company's NOLC that should be reflected for this purpose. All parties agree that the Company's actual federal NOLC is approximately $215 million. That notwithstanding, MIEC proposes to use a federal NOLC of just approximately $70 million in the Company's ADIT calculation. The variance between the two figures, approximately $145 million, produces an ADIT differential of approximately $51 million ($145 million x 35%) by which MIEC proposes to reduce the Company's rate base.

[74] Ex. 48, p. 17, l. 6-10.
[75] Ex. 501, p. 26, l. 14-18 (Brosch Direct).
[76] Ex. 502, p. 5, l. 8 to p. 6, l. 6 (Brosch Surrebuttal).
[77] Tr. p. 350, l. 8-17.

Ameren Missouri is included in a consolidated federal income tax return of which Ameren Corporation is the common parent. Filing on a consolidated basis is extremely common.[78] The main reason for filing on this basis is that it enables companies producing taxable income to offset that income by tax losses incurred by other members of the group. As a result, a consolidated group often pays less in income tax than the sum of the income taxes each of the members would have paid had they filed separate tax returns. For this reason, virtually all groups of companies that are able to file on a consolidated basis do so.[79]

The election to file on a consolidated basis was made many years ago. No one has alleged that this election was imprudent and, in fact, as is discussed hereafter, the Company and its customers have benefitted materially from filing in that fashion. Under the applicable tax rules, once an election to file on a consolidated basis is made, all corporations that meet the ownership and control requirements of the tax law must be included. There is no ability on the part of one or more members to opt out. Further, once the election is made, the group must continue to file on a consolidated basis. If a group wants to cease consolidated filing, it must apply to the IRS for permission and demonstrate good cause. Cessation is not a unilateral right. And once a group ceases to file on a consolidated basis, consolidated filing cannot be resumed for five years. Thus, a company cannot move in and out of consolidated filing at will. Such movement is highly restricted.[80]

Under the tax rules, NOLCs are computed on a consolidated basis. That is, if a group produces consolidated taxable income in a given year, no member produces an NOLC in that year no matter how large its tax loss is. Under such circumstances, all tax losses produced in that year are used to offset the taxable income of other members. This is a good thing. It means that

[78] Tr. p. 369, l. 5-10.
[79] Ex. 48, p. 23, l. 10-13.
[80] Tr. p. 353, l. 2 to p. 354, l. 21; Ex. 48, p. 23, l. 14-18.

the tax losses of members who might not be able to use them immediately had they filed separately, in fact, get used immediately. This is what makes consolidated filing so attractive.[81] If, instead, a group produces a consolidated tax loss (or no positive consolidated taxable income) in a given year, there are two relevant consequences. First, a ratable portion of each member's tax loss is deemed to be used to offset any taxable income produced by other members. Second, none of the consolidated NOLC from prior years is used because there is no consolidated taxable income which it can offset. That means that no individual member's NOLC from prior years is used. Where there is a consolidated tax loss, it is possible that a member who has an NOLC from prior years will not be able to use that NOLC in the current year even if it produces taxable income.[82] The Company's financial accounting and tax allocation practices are, and have been, consistent with these tax law rules.

During the time period addressed in the testimony in this case (2008 through 2014), Ameren Missouri experienced situations in which it was paid for the use of losses it generated and which it could not have used had it filed separate income tax returns but which were used because, due to consolidated filing, they offset the taxable income of other members. The Company also experienced situations in which it generated taxable income but its NOLC could not be used because the group produced a consolidated loss. The results were presented at page 2 of Schedule MLB-10 attached to Mr. Brosch's surrebuttal testimony,[83] which follows:

[81] Ex. 48, p. 18, l. 18 to p. 20, l. 13 (Warren Rebuttal).
[82] Ex. 48, p. 20, l. 14 to p. 23, l. 7.
[83] Ex. 502.

Table VII (updated)

	(1)	(2)	(3)	(4)	(5)	(6)
	"Stand Alone" Ameren Missouri Taxable Income/(Loss) By Year	**Cumulative "Stand Alone" Ameren Missouri NOLC**	**Consolidated NOLC Allocated to Ameren Missouri By Year**	**Cumulative Consolidated NOLC Allocated To Ameren Missouri**	**Excess of Cumulative "Stand Alone" NOLC (2) Over Consolidated NOLC (4)**	**Approximate Ameren Missouri Rate Base Decrease/(Increase) Due to Filing Consolidated (5) X 35%**
2008	($461,008,006)	($461,008,006)	($97,421,862)	($97,421,862)	($363,586,144)	$127,255,150
2009	($162,043,265)	($623,051,271)	($65,062,485)	($162,484,347)	($460,566,924)	$161,198,423
2010	($130,775,965)	($753,827,236)	($53,170,203)	($215,654,550)	($538,172,686)	$188,360,440
2011	$17,970,962	($735,856,274)	$0	($215,654,550)	($520,201,724)	$182,070,603
2012	$12,890,120	($722,966,154)	$0	($215,654,550)	($507,311,604)	$177,559,061
2013	$598,155,735	($124,810,419)	$0	($215,654,550)	$90,844,131	($31,795,446)
2014 est	$55,099.858	($69,710,561)	$0	($215,654,550)	$143,943,989	($51,080,396)

In 2008 through 2010, the Company produced significant tax losses that it would not have been able to use had it filed separate income tax returns in those years.[84] However, because other members of the group produced taxable income, the Company was able to use significant

[84] See Column (1) for 2008, 2009 and 2010.

portions of the losses it produced in those years (all but approximately $215 million).[85] It was paid for the use of the used losses through the tax allocation process adopted and consistently used among the consolidated group of which Ameren Missouri is a member. As a result of the payments, the Company came into possession of a good deal more cost-free capital (approximately $127 million in 2008, another $34 million in 2009 and an additional $27 million in 2010[86]) than it would have possessed had it filed separate tax returns in those years.[87] Consequently, as of the end of 2010, Ameren Missouri was sitting with $188 million more cost-free capital than it would have had it filed separate income tax returns for those years.[88] In 2011 and 2012 the Company produced modest amounts of taxable income (approximately $18 million and $13 million, respectively).[89] While it had an NOLC from prior years, due to the fact that the consolidated group produced tax losses in each of those two years, that NOLC could not be used. Thus, in each of those two years, the Company "gave back" a small amount (approximately $6 million and $5 million respectively)[90] of the comparative benefit it had accumulated in 2008 through 2010, leaving it still "ahead of the game" by approximately $177 million.[91] What this means is that when rates were reset in 2009, 2010 and 2013, the rate base (and consequently the revenue requirements) in each of those cases was significantly lower than it would have been had the standalone approach MIEC advocates for now had been used.

In 2013, the Company produced a large amount of taxable income while the consolidated group still produced a tax loss and because of the consolidated tax loss, none of the Company's

[85] The amount of the Company's loss which was used to offset the taxable income of other members of the group in each of those years is the difference between Column (1) and Column (3) or $363,586,144 (2008), $96,980,780 (2009) and $77,605,762 (2010).
[86] Ex. 48, p. 25, l. 15 to p. 27, l. 12; Ex. 502, p. 10, l. 10-21.
[87] The payment the Company received for each year is the simply the loss amounts set forth in footnote 7 (Ex. 502) multiplied by the tax rate (35%) or $127,255,150 (2008), $33,943,273 (2009) and $27,162,017.
[88] See Column (6) in the above table for 2010.
[89] See Column (1) for 2011 and 2012.
[90] This amount is equal to the taxable income it produced multiplied by 35%.
[91] See Column (6) for 2012.

NOLC from prior years could be used in that year. As a consequence, the cumulative benefit Ameren Missouri had enjoyed during the four-year period 2008 through 2012 as a result of consolidated filing disappeared and for the first time the Company would have been better off (in terms of the quantity of cost-free capital it possessed) had it always filed separate income tax returns. The amount of the cumulative difference in cost-free capital as of the end of 2013 approximated $32 million.[92] However, rates were not reset in 2014 so the rate base (for ratemaking purposes, which was significantly lower due to the use of the actual consolidated results) that had last been used to reset rates was unaffected. In 2014, the consolidated group's overall tax losses again precluded the Company from using its NOLC, adding another approximately $19 million to the difference between what rate base would have been had a standalone approach always been used versus what rate base is using the consolidated approach.[93] The result is that for the first time, rate base will be higher in this case (by $51,080,396).

As noted, in its rate base calculations in each rate case, the Company reflected the quantity of ADIT dictated by the tax law, the Company's tax allocation agreement applied to it as a consolidated taxpayer group member and its financial accounting records. In other words, it reduced rate base by the quantity of cost-free capital it *actually possessed* as of the end of the test period in each case. Given the purpose of reducing rate base by ADIT, this makes perfect sense.

[92] See Column (6) for 2013.

[93] Mr. Brosch points to the tax loss incurred on the 2013 disposition of the competitive generation companies formerly owned by Ameren Corporation as somehow "world changing." (Tr. p. 389, l. 4-5; p. 400, l. 12-22) In fact, an equivalent loss produced by the operations of any Ameren affiliate in 2013, including regulated affiliates, would have produced precisely the same result. In fact, in 2014, the year *after* the year in which Ameren Corporation sold the companies that comprised the competitive generation business, the same thing that happened in 2013 (that is, the Company produced positive taxable income but none of its NOLC could be used due to a consolidated loss) happened again. Obviously, the effect upon which Mr. Brosch premises his proposed adjustment is not a creature of Ameren Corporation's 2013 divestiture.

The Company's calculation accurately measures the quantity of its rate base that is supported by investor and creditor provided capital.[94]

MIEC proposes to compute ADIT (and, hence rate base) *in this particular case* by reference to what it would have been had the Company always filed its income tax returns on a separate basis. In so doing, it proposes to substitute a fictional filing status for the real one. It proposes to substitute a fictional number for the real one. It proposes to substitute a fictional economic status for the real one.

MIEC's witness, Mr. Brosch, proposes that, in computing the Company's rate base, the Commission respect the reality that the Company files as part of a consolidated return group when that is better for customers (which was the case by a very large margin in the past three rate cases) but that it utilize a fictional ADIT amount (as if the Company had always filed separate income tax returns) when that is better for customers, as it happens to be in this one case.[95] The primary rationale offered by MIEC for this patent disregard of reality is that the quantity of cost-free capital at any point in time is dictated by the consolidated group's tax allocation agreement and that this arrangement should be subjected to the Commission's affiliate transaction rules – or, even if not technically subject, that the same rules should be applied as a matter of "regulatory policy."[96] Under the affiliate transaction rules, the price presumed for ratemaking purposes in connection with goods or services transferred to a utility by an affiliate is the lesser of "fully distributed cost" or "fair market price."

[94] Ex. 48, p. 17, l. 6-10.
[95] Ex. 502, p. 14, l. 1-6.
[96] *Id.*, p. 13, l. 5-22. MIEC's retreat from the unsupported position expressed in its testimony evidences a willingness to overstate its case in an effort to opportunistically create a fictional lower rate base than the actual NOLCs possessed by the Company simply because doing so would lower rates, never mind the benefits, customers have received for several years as a result of using the actual cost-free capital the Company possesses.

There are at least four flaws in MIEC's theoretical application of the affiliate transaction rules to the NOLC issue:

- the tax allocation agreement does not involve the transfer of any goods or services to the Company by its affiliates;
- in the case of tax allocation, there exists no conceptual basis upon which to determine what would be "fully distributed cost" and what would be "fair market price," as there is when dealing with goods and services;
- it ignores the reality that each year's tax allocation is not a separate "transaction" but is, instead, part of an ongoing process that has been in place for years and which flows from the long-ago decision to file as a consolidated group; and
- the Company's methodology has served its customers very well for years and is, and has been, both prudent and equitable.

First and foremost, contrary to statements he made in his pre-filed direct and surrebuttal testimony, at hearing, MIEC's witness, Mr. Brosch, testified that he was *not* asserting that the Missouri affiliate transaction rules compelled the Commission to accept his proposal. (Tr. 401, 16-21) Instead, he merely opined that it would be "good policy."[97]

But, it is hard to fathom how the affiliate transaction rules (or a policy that mirrors them) even could be applicable. The allocation of the consolidated tax liability does not involve a transfer of anything. The only difference between the consolidated and separate return NOLC amounts relates to how fast the Company's own NOLC is used. The Company is never allocated all or a portion of some other member's NOLC and no other member is ever allocated all or any portion of the Company's NOLC. Thus, even if Ameren Missouri's NOLC is considered a free-standing asset (as opposed to a reduction or adjustment to its ADIT liability), it is an asset that is created by Ameren Missouri. Contrary to Mr. Brosch's implications, there are no tax losses transferred between group members. The tax allocation agreement – consistent with the tax law

[97] Tr. p. 401, l. 12-15.

– only determines whose tax losses are used to offset any member's positive taxable income. Thus, given that application of the affiliate transaction rules is premised on the transfer of goods or services, they cannot be applicable to tax allocation. And Mr. Brosch is aware of no instance in which the Missouri rules – or those of any other state – have been so applied.[98]

Even if an attempt were to be made to apply such rules to tax allocation, the testimony is entirely devoid of any discussion that would help identify what would be "fully distributed cost" and what would be "fair market price" in this context. Is the consolidated ADIT amount "fully distributed cost" or "fair market price" – or neither? The same question applies to the separate company ADIT amount. In point of fact, MIEC is not the slightest bit concerned about applying the lower of "fully distributed cost" or "fair market price" standard of the affiliate transaction rules. The broader principle it supports is "lower rates" regardless of the reason.[99]

The allocation of taxes pursuant to a tax allocation agreement is an ongoing process, not a series of discrete transactions. The tax allocation process used by the consolidated group is conducted pursuant to an arrangement put in place many years ago. It is not negotiated each year. It is, essentially, self-executing. To analyze the Company's tax allocation under the affiliate transaction rules (or any variation thereof), it is the entire process, and not just any one year's results, that must be evaluated.

Setting aside the affiliate transaction rules, the essence of Mr. Brosch's proposal is to use whatever tax allocation methodology produces lower rate base and, hence, lower rates in the particular rate case in which the calculation is being made. Thus, he would support the use of the consolidated method in the Company's rate cases where the test periods included 2008 through 2012. However, he proposes his fictional separate tax return allocation method in this case. He

[98] Tr. p. 394, l. 16-20.
[99] Tr. p. 404, l. 19-23.

further suggests that, if, in a subsequent (or even the next) rate case, the consolidated allocation method produces a lower rate base, he would support switching back. While he does not accept the Company's characterization of his approach as "cherry picking," it is hard to conjure up a more apt description. And, while Mr. Brosch is aware of one or perhaps two instances in which a utility, on its own accord, proposed to measure its NOLC on a fictional separate return basis, he is unaware of any instance in which a utility, either voluntarily or by regulatory directive, adopted a methodology that would allow for regular switching of its measurement regime from one rate case to the next simply because it would produce lower rates.

There is absolutely no evidence that the consolidated group's tax allocation practice, as a process, is imprudent or detrimental to customers. Indeed, during the time period reviewed in this proceeding, it benefitted customers for five of the seven years reviewed.[100] Further, the cumulative benefits the Company derived during those five years far outweigh the detriment of the most recent two years.[101] The fact that, in 2013 and 2014, that process did not benefit the Company doesn't negate the value it has brought to the Company and the consolidated group. Yes, Mr. Brosch's proposed adjustment would produce lower rates. However, that adjustment would be based on a benefit (a greater quantity of ADIT) that the Company does not, in fact, possess. It is a fiction. As a result, his proposal would effectively amount to an outright transfer of funds from shareholders to customers. Lower rates, yes. Just and reasonable rates, no.

B. The domestic production deduction.

The domestic production deduction ("DPD") is a tax incentive Congress provides to manufacturers. The tax law permits a business to claim a tax deduction, the DPD, equal to 9% of the lesser of certain qualified net income (referred to as QPAI) or the taxpayer's taxable income.

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[100] Tr. p. 404, l. 24 to p. 405, l. 2.
[101] Tr. p. 333, l. 1-14; p. 337, l. 8-19.

To qualify as QPAI, the net income has to be derived from specified activities associated with manufacturing. The generation of electricity is an eligible activity.

The Company included a DPD in its filing which had the effect of reducing the tax expense element of cost of service. MIEC proposes to increase the number the Company used. MIEC's primary position is that the Company should not be allowed to factor any amount of its NOLC into the DPD calculation because it has not done so in prior rate cases. In short, MIEC proposes that the Company be compelled to follow its past practice just because it "always has been done that way." MIEC's alternative position is that, even if the Commission concludes that the Company's NOLC ought to be factored into the DPD, the NOLC so considered ought to be the NOLC the Company would have produced had it always filed separate income tax returns rather than its actual NOLC; i.e., it should disregard the actual cost-free capital the NOLC provides, as discussed above. Finally, MIEC asserts that its proposed adjustments are justified because the DPD is based on certain projected results and is not really knowable anyway.[102]

Both Company witness Warren and MIEC witness Brosch agree that, under the tax law, the Company's DPD *is* limited by its taxable income.[103] In other words, the Company's DPD for any year cannot exceed its taxable income (before considering the DPD) for that year. When the Company computed its taxable income for determining this limitation, it properly included its NOLC deduction in the calculation.

In his direct testimony, MIEC witness Brosch disputed the Company's inclusion of its NOLC in its computation of the taxable income limitation asserting that the tax law does not support it.[104] In response, Mr. Warren testified that the tax law defines "taxable income" for this

[102] Tr. p. 410, l. 17 to p. 411, l. 14; Ex. 502, p. 22, l. 5-12.
[103] Tr. p. 395, l. 17 to p. 396, l. 2; Ex. 48, p. 31, l. 7-9.
[104] On page 10, lines 16-20 of his direct testimony (Ex. 501), Mr. Brosch states: "The Section 199 Production Deduction allowed under the tax code does not rely upon cumulative taxable income/loss balances in any way, but

purpose to include consideration of the Company's NOLC.[105] His rebuttal testimony included an excerpt from the tax regulations that supported this statement.[106] On cross-examination, Mr. Brosch appeared to concede that the tax law mandates consideration of an NOLC in computing the taxable income limitation.[107] However, he continues to assert that no NOLC should be considered because the Company did not do so in its prior rate cases.[108]

Mr. Warren testified that the Company's failure to consider its NOLC for purposes of computing the DPD in prior cases was a technical error. It was flat out wrong. Having recognized its mistake and believing it unreasonable to perpetuate the error, the Company corrected it. Mr. Warren pointed to the Company's concession regarding its treatment of the Account No. 281-related ADIT balance. In prior cases, the Company had excluded this balance from its rate base computation. It did so again in this case when it filed its direct testimony. In his direct testimony, Mr. Brosch for the first time challenged this exclusion. It having been pointed out to the Company that its prior exclusion of the Account No. 281-related ADIT balance was in error, the Company accepted Mr. Brosch's significant adjustment (a $78.8 million decrease to rate base), thus correcting the error.[109]

There is no technical dispute here.[110] The Company's use of its NOLC is necessary under the tax law. MIEC is proposing that the Commission ignore that law because the Company inadvertently and erroneously did so before. It relies on computational precedent.

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instead is a calculation of current tax year DPGR, reduced by production-related costs and direct as well as reasonably allocated indirect expenses."

[105] Ex. 48, p. 32, l. 4-10.

[106] Ex. 48, p. 32, l. 13 to p. 33, l. 2.

[107] Tr. p. 395, l. 3-6.

[108] Tr. p. 410, l. 23 to p. 411, l. 1. In opposing the inclusion of coal-in-transit in rate base in File No. ER-2012-0166, the Staff argued that it should be excluded because it had been excluded in the past. The Commission said the past exclusion was irrelevant, evidencing the Commission's desire to reach the right result. The same principle applies here.

[109] Ex. 48, p. 8, l. 14 to p. 9, l. 12; Tr. p. 322, l. 1 to p. 324, l. 22.

[110] Tr. p. 375, l. 4-11.

However, in a very similar situation where computational precedent increased rates, the Account No. 281 ADIT balance, MIEC is perfectly willing for the Company to correct its mistake. Income tax is a cost of providing the Company's regulated service. It is imposed by the tax law. The ratemaking process is supposed to incorporate this cost into the setting of rates. While this Commission may have discretion in determining the level of income tax cost which is properly associated with the Company's regulated activities, it has no ability to change the tax law, nor should it. Yet that is precisely what MIEC is asking it to do. On this basis, MIEC's primary position with regard to the DPD should be rejected.

MIEC's alternative position is that the NOLC used in computing the DPD taxable income limitation should be a hypothetical, not the Company's actual, NOLC. Specifically, it is the NOLC the Company would have had if it had always filed its income tax returns on a separate company basis instead of the NOLC it actually has as a member of the Ameren consolidated group. MIEC's arguments in support of this alternative are identical to those that it asserts in support of its proposal regarding the use of the same NOLC in the computation of rate base. All parties agree that whatever NOLC is used for purposes of the ADIT (*i.e.*, rate base) computation should also be used in computing the DPD taxable income limitation.[111] The Company therefore relies on its discussion earlier in this brief regarding ADIT in opposition to MIEC's alternative DPD position.

MIEC's assertion that the uncertainty of the Company's future taxable income constitutes a reason in support of either of its two proposed adjustments to the Company's DPD[112] is logically flawed. First, if the DPD deduction is that uncertain, perhaps it should not be computed at all based on the fact that it is neither known nor measurable, in which case customers would

[111] Tr. p. 375, l. 23 to p. 376, l. 5; Tr. p. 376, l. 21 to p. 377, l. 7; Tr. p. 396, l. 24 to p. 397, l. 8.
[112] Ex. 502, p. 22, l. 5-12.

obtain no benefit. But, that aside, of all the components that go into computing the DPD, the most certain of all is the Company's NOLC. That number as it exists as of the end of 2014 has been calculated and recorded on the Company's financial statements, reported to the Securities and Exchange Commission and, thereby, to the Company's holders of registered securities. Under these circumstances, the assertion that computational uncertainty in any way supports either of MIEC's proposed DPD adjustments borders on the ironic.

V. NORANDA LOAD

During the roughly 10 years Noranda has been an Ameren Missouri customer, its load has varied significantly – it most certainly has not stayed at "full" (98%) load. This is shown by a table from Ameren Missouri witness Steve Wills' rebuttal testimony:

Table SMW-1[113] from Wills' Surrebuttal

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Noranda Load Factor	97.0%	98.4%	98.6%	98.2%	58.0%	95.7%	98.1%	97.3%	98.4%	95.4%

In spite of this variation, the Staff has incorrectly assumed that Noranda's load does not vary and does always stay at full load. This is in spite of the fact that in most instances where there is variation in a factor impacting rates (whether that be an expense or the usage of a particular class), the factor is normalized or annualized. For example, in the Staff Cost of Service Report, Staff witness Sarah Kliethermes explained how billing units (which are a reflection of the amount of test year usage of a customer class that should be the basis of the rate calculation) are set for the Company's Large Primary Service ("LPS") rate class:

> The adjustments to billing units and revenues were based upon an "update period" of August 1, 2013, through July 31, 2014, to be adjusted for known and measurable changes through the true-up period ending December 31, 2014. There were 73 customers in the

[113] Ex. 54, p. 6, l. 12 (Wills Surrebuttal).

> LPS rate class during the update period. A data check was performed for billing corrections prior to doing other adjustments. LPS customers were annualized on an individual customer (account) basis. Their individual monthly demand and energy use, measured over multiple years prior to the update period and the twelve (12) months of the update period, were examined graphically to determine if an adjustment was needed to reflect an annualized/normalized level of demand and energy use for the 12-month update period, as well as to identify the type of adjustment required to reflect the appropriate annualized/normalized level.[114]

For the Large Transportation Services ("LTS") class, however, Staff decided to presume that the LTS class (which is only Noranda) would go back to test year usage levels (the 98% load factor) and so did not use the update period to adjust billing units and revenues from Noranda. Unlike what Staff did for the LPS class, Staff did not compare monthly demand and energy use over multiple years prior to the update period and compare it to the update period. Instead, Staff took the unique approach of presuming Noranda would return to full load, that its load would not vary at all, and also ignored the update period.[115] Ms. Kliethermes confirmed Staff's choice in her Surrebuttal Testimony:

> Staff recommends use of the normalized LTS billing units included in Staff's direct case, reflecting an assumption that reduction in energy consumption during the update period is not normal and should not be expected to continue going forward.[116]

This assumption is especially risky since Noranda is the only LTS customer. Consequently, there is no other customer who might increase its load when Noranda decreases its load and thus nothing to offset the risk of Staff's assumption being untrue. If Noranda does not return to full load or continues to have fluctuations in load (even if for a time it does return to "full" load), then setting rates presuming it will use more electricity than it actually does use

[114] Ex. 202, p. 64, l. 19-29 (Staff Report Revenue Requirement Cost of Service Report).
[115] As addressed in testimony and during the evidentiary hearings, Noranda's load during the 12 months ending with the true-up period were significantly less than its test year usage due to pot failures at its smelter that started to appear in the summer of 2014 and that have continued.
[116] Ex. 222, p. 32, l. 4-6 (S. Kliethermes Surrebuttal).

means Ameren Missouri will receive revenues insufficient to cover all of the costs assigned the LTS class.[117]

Consequently, in order to adopt Staff's recommendation, the Commission must accept that Noranda will go back to, *and stay at*, the presumed "full load." It is not sufficient for the Commission to simply accept Noranda's contention that the pots that have failed will be fixed (a contention that itself is unproven). Indeed, at the time of the hearing, almost eight months after the end of the test year, Noranda still was not at "full" load and had not completed repairs of the pots that had failed.[118]

Noranda's "return" to full load has been elusive. In November 2014, Noranda told Wall Street that it expected to have all its failed pots repaired during the "first part" of 2015.[119] Then, it claimed it would have them all repaired by the end of the first quarter.[120] The goal post has apparently moved again given Mr. Meyer's testimony (hearsay though it is) that Noranda now does not expect repair to be done until May.[121]

Regardless of when (or if) Noranda gets all of the pots repaired, the bottom line is that for the Commission to use Staff's recommendation it has to conclude that even if the pots are soon repaired, there will be *no other reason* which will cause Noranda's electric usage to drop from time-to-time, even though history shows that in fact it has dropped from time-to-time. Such a conclusion would be an unreasonable one. As shown in the table from Mr. Wills' Surrebuttal Testimony shown above, Noranda's actual load has only been at or above 98.2% during only four of the ten years Ameren Missouri has been Noranda's electric service provider. And during

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[117] There is a point when a decrease in Noranda load would trigger the use of what has sometimes been referred to as the "N Factor" in the FAC tariff, but the existence of that factor should not mean that a normalization of a factor that fluctuates should simply be ignored.
[118] Tr. p. 253, l. 17-25.
[119] Ex. 72.
[120] Schedule GRM-SUR-4 to Mr. Meyer's Surrebuttal Testimony (Ex. 514).
[121] Tr. p. 2099, l. 13-24.

the majority of those six years, there was no major event causing the lower usage – no severe ice storm or significant pot failures. Noranda's electrical use varies, period. No party in the case introduced any evidence to the contrary.

So how much energy will Noranda use going forward? One cannot know the answer to that question, but that can be said of every cost and revenue used to set a revenue requirement upon which rates are set. But Ameren Missouri, using actual historical data, has proposed a fair normalization of a factor that undeniably fluctuates. While an argument could certainly be made to ignore Noranda's usage levels post-the end of the update period and to just set its usage in this case at the usage during the update period (or even to use a longer period of time to compute a normalized level of usage), the best reflection of Noranda's normal usage – and the fairest resolution of this issue – is to use a three-year average of its actual usage, as is commonly done to normalize fluctuating items. This represents a normalization adjustment which accounts for the observed variability in Noranda's load over time, as all normalizations are designed to do. This results in using a load factor of 97% or setting Noranda's usage equal to 4,139,345 MWh annually.[122]

VI. RETURN ON EQUITY

The electric utility business is capital intensive.[123] This case demonstrates that point well. The Company reduced O&M expenses in a significant way since its last rate filing, but its capital investment between rate cases included large capital expenditures such as the Callaway reactor vessel head, Labadie ESPs, large substation replacements and the O'Fallon solar generation facility. Those items as well as numerous other generation, transmission and

[122] Ex. 54, p. 8, l. 1 (Wills Surrebuttal). While a 97% load factor and 4,139,345 MWhs may at first blush appear "close" to a 98% load factor and the 4,191,014 MWhs Staff proposes to use, the 51,669 MWH difference is material in terms of revenue requirement and represents a difference in annual revenues of approximately $1.7 million. Staff's Final Reconciliation, EFIS Item 211.

[123] Ex. 16, p. 35, l. 13-18 (Hevert Direct).

distribution projects are part of the Company's rate base. That rate base represents the plant Ameren Missouri uses to provide service to customers in the State's largest municipality and many other areas. The electric utility infrastructure supported by on-going capital investment is critical to our communities and to the Missouri economy. Maintaining a financially viable utility worthy of investment is in the long-term best interest of not only the Company's investors but customers and the state generally. Capital markets are competitive, there is no dispute. It follows that the return opportunity afforded to equity investors must be competitive as well.

The Company's capital investments are in large part not discretionary. Environmental, reliability and aging infrastructure requirements are not matters the Company can ignore.[124] Some of the parties have argued the return on equity is a discretionary matter for the Commission, as though the return the Commission decides is removed from practical constraints and can simply be a matter of purely subjective considerations.[125]

Some parties further argue that the cost of capital is declining.[126] A closer review indicates this position statement is without evidentiary support and indeed the evidence is contrary. As Ameren Missouri witness Robert Hevert pointed out at hearing, interest rates are relatively consistent with and in fact are slightly higher than they were in 2012, when Ameren Missouri's last rate case was decided.[127] MIEC witness Michael Gorman's testimony corroborates this conclusion. Mr. Gorman admits that his Capital Asset Pricing Model ("CAPM") contains a measure of the risk-free rate (calculated using Treasury rates) that is 40 basis points higher in this case than what he relied upon in the Company's last rate case.[128] OPC witness Lance Schafer testified he believes that the Federal Reserve will move to increase

[124] Ex. 16, p. 35, l. 6 to p. 36, l. 20.
[125] Tr. p. 1105, l. 9-14.
[126] Tr. p. 1097, l. 2-25.
[127] Ex. 18, p. 7 (Hevert Surrebuttal); Tr. p. 1150, l. 12 to p. 1151, l. 17.
[128] Tr. p. 1217, l. 4 to p. 1218, l. 15.

interest rates this year.[129] Mr. Gorman's analyst growth rates, those he relies upon as part of his Discounted Cash Flow ("DCF") analysis, are also higher in this case than they were in the Company's last rate case.[130] An examination of national average returns also demonstrates that the national average return for vertically integrated electric utilities remains stable since the last case, at around 10%, which is higher than the Company's present authorized return of 9.8%.[131] Mr. Gorman also reports the economy has improved in the past 24 months based on his assessment of improvements on key economic indicators.[132]

By deduction, we can conclude that the other parties are choosing to focus on one singular measure of capital market conditions to support their claim: dividend yields. However, there is substantial evidence to show that the yields are the result of stock price aberrations during the measurement periods used by those witnesses.[133] To be clear, no party is claiming that utilities have been reducing dividends because the historic levels are no longer needed to support investment. Rather, dividend yields are a product of the annualized dividends divided by stock price.[134] An increase in stock price results in a lower yield.[135] Mr. Hevert explained at hearing how unusually high price/earnings ("P/E") ratios were affecting DCF models and that today's high stock valuations will return to historic levels.[136] Indeed, as it turns out, both Mr. Hevert and Mr. Schafer observed steep declines in stock prices for the utility sector just prior to the evidentiary hearings.[137] Mr. Hevert further explained how dividend yields increased

[129] Tr. p. 1318, l. 8-16.
[130] Tr. p. 1221, l. 2-10.
[131] Ex. 18, p. 6, l. 11 to p. 7, l. 5.
[132] Tr. p. 1221, l. 22 to p. 1222, l. 4.
[133] Ex. 18, p. 9 to p. 10, l. 2.
[134] Tr. p. 1192, l. 21 to p. 1193, l. 3.
[135] *Id.*
[136] Tr. p. 1168, l. 2 to p. 1169, l. 22; Ex. 18, p. 9.
[137] Tr. p. 1152, l. 22 to p. 1153, l. 8; Tr. p. 1316, l. 5-20.

approximately 40 basis points in a short period of time prior to the evidentiary hearings.[138] Mr. Schafer even acknowledges that analysts (Value Line) he relies upon for his analysis forecast yield for his proxy group of companies to move higher to 4.4% – closer to what Mr. Schafer identifies as a historic normal level of 4.5% (which is significantly higher than the 3.5% yields Mr. Schafer used in his DCF analysis).[139] There is no evidence to suggest that the low yields impacted by high stock valuations are here to stay. To the contrary, the record establishes clear indications yields are growing rapidly and they will return to normal levels in the near future when rates set in this case would be in effect.

The argument that capital markets have declined is a familiar refrain from parties like MIEC, but the record does not sustain this conclusion. The record demonstrates conclusively that capital markets today are as competitive as they were in 2012, and all indications suggest an improving economy, a return to normal utility dividend yields, increasing interest rates, and higher investment growth expectations going forward.

Accordingly, the Company's proposed range of returns between 10.2% and 10.6% is reasonable, and its point estimate of 10.4% is well supported. Accordingly, the Commission should approve a reasonable and supported return consistent with Mr. Hevert's recommendations.

A. Applicable law and authority.

The law with respect to establishing a return on equity is well settled. It is plainly not a discretionary standard. The two lead cases that establish the constitutional parameters concerning return on capital and the ratemaking process are the decisions rendered in ***Bluefield Water Works and Improvement Co. v. Public Service Comm'n of West Virginia*** and ***Federal***

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[138] Tr. p. 1153, l. 17-21.
[139] Ex. 409, p. 15, l. 19 to p. 16, l. 7 (Schafer Direct); Tr. p. 1314, l. 22 to p. 1315, l. 1.

Power Commission v. Hope Natural Gas Co. Those two cases set forth the following requirements: (1) the return must be comparable to investments of similar risk, (2) the return must be sufficient to ensure confidence in the company's financial integrity, and (3) the return must be adequate to maintain and support the company's credit and attract capital. ***Bluefield***, 262 U.S. 679, 679 (1923); ***Hope***, 320 U.S. 591, 603 (1943). Missouri appellate decisions also clarify that the Commission may consider the service quality of a utility in setting the authorized return on equity, and may award a higher return for superior service. ***State Ex. Rel. Public Counsel v. Public Service Comm'n***, 274 S.W.3d 569, 573 (Mo. App. W.D. 2009). Missouri Courts also require that the return on equity be based upon substantial and competent evidence. *Id.* at 573.

A review of recent Commission rate case orders provides further guidance with respect to what evidence the Commission has traditionally considered in order to establish a return consistent with the above stated standards. In the two *most recent* rate cases decided by the Commission, both gas cases, the Commission considered several methods for measuring the market cost of equity. *Report and Order*, File No. GR-2014-0152, pp. 22-26 (*In the Matter of Liberty Utilities*, establishing a return on equity equal to 10%); *Report and Order*, File No. GR-2014-0086 (*In the matter of Summit Utilities*, establishing a return on equity equal for gas operations equal to 10.8%). Regarding the use of multiple methods to arrive at a return, the same conclusion can be ascertained from a review of recent Commission decisions in Ameren Missouri rate cases. See e.g. *Report and Order*, File No. ER-2012-0166, pp. 63-73; *Report and Order*, File *No. ER-2011-0028*, pp. 63-74; *Report and Order*, File No. ER-2010-0036, pp. 14-25. The Commission also recognizes that no singular return estimate can be found to be correct, and that no single test can be used to determine the cost of equity. *See e.g., Report and Order*, File

No. 2010-0036, p. 17. In a recent case (*Summit*) involving a disputed return on equity and cost of capital, the Commission took into consideration the interests of maintaining the financial condition of the subject utility and establishing a return that promotes infrastructure investment in a socially beneficial manner. See *Report and Order*, File No. ER-2014-0086, p. 13; 45.

With respect to the methods relied upon, a review of rate decisions (those cited above) indicates that the Commission has given specific consideration to the results of expert witness testimony concerning DCF and CAPM analyses. *See e.g., Report and Order,* File No. GR-2014-0152, pp. 22-25. With respect to the DCF analysis, the Commission considers both the results of constant growth and multi-stage DCF models. The Commission has also considered the results bond plus risk premium models, and considered generally authorized rates of return approved by other Commissions. *See e.g.*, *Report and Order*, File No. ER-2012-0166, pp. 66-67. Witnesses have offered other methods in past cases including calculations lifted from special purpose corporate financial reports, and the "sustainable growth" form of the DCF model, but the Commission has properly declined to accept such methods. *See Report and Order*, File No. ER-2011-0028, pp. 69-70; 71-72.

B. Expert testimony.

Four parties submitted testimony prepared by expert witnesses with respect to the return on equity. Mr. Robert Hevert for the Company, Mr. Mike Gorman for MIEC, Mr. Lance Schafer for OPC and Mr. David Murray for the Staff.

Mr. Hevert presented testimony supporting a reasonable range of returns between 10.2% and 10.6%, with a point estimate of 10.4%.[140] Messrs. Gorman, Schafer and Murray all presented much lower point estimates, equal to 9.3%, 9.01%, and 9.25% respectively.[141] Both

[140] Ex. 16, p. 42, l. 5-10 (Hevert Direct).
[141] Ex. 510, p. 42, l. 1 (Gorman Direct); Ex. 409, p. 3, l. 14; Tr. p. 1341, l. 4-6.

Mr. Gorman and Mr. Murray raise their recommended returns when considering the allowed returns from other jurisdictions, acknowledging (at least implicitly) that investors consider that information. Considering this evidence, Mr. Murray's and Mr. Gorman's estimates of required returns would be 9.5% and 9.63%, respectively.[142] Mr. Schafer acknowledges other authorized returns in other jurisdictions, but attempts to minimize the implications of such results in comparison to his very low recommendation of 9.01%.

One additional witness offered testimony concerning the return on equity, Mr. Chriss on behalf of Walmart, but Mr. Chriss offered no modeling or analysis to support his recommendation to hold Ameren Missouri's return on equity at 9.8%.[143] Because Mr. Chriss does not offer supportive analysis using the methods that the Commission has traditionally accepted, his testimony is more a statement of position or preference than evidence with respect to the cost of equity for Ameren Missouri.

As detailed below, there are very straightforward reasons why Staff, OPC and Intervenor witnesses are clustered at very low recommended returns that are far below the other authorized returns. The disparity between prevailing returns and Staff, OPC and Intervenor recommendations is the result of limited inputs and a results-oriented pessimism that underlies key assumptions that drive the output of their models.

Each of the methods and merits of the four expert witnesses that analyze the cost of equity are discussed in detail below, beginning with Mr. Hevert.

i. Mr. Hevert's analysis.

The most persuasive and authoritative as demonstrated by the weight of the evidence is Mr. Hevert. Mr. Hevert offers informed testimony based upon a variety of methods, including a

[142] Tr. p. 1358, l. 15-24; Ex. 512, p. 3, l. 23.
[143] Ex. 750, p. 13, l. 13-14 (Chriss Direct).

constant growth DCF, a three-stage DCF, a CAPM, and a Bond Plus risk premium.[144] Mr. Hevert also offers testimony concerning recently authorized returns, and provides an assessment of business risk and current capital conditions.[145]

Mr. Hevert testified in Ameren Missouri's last rate case, and most recently testified in the Liberty Utilities gas rate decided on December 3 of 2014. *File No. GR-2014-0152.* In that case, the Commission specifically found that Mr. Hevert's methodologies, Constant growth DCF, three-stage DCF, bond plus risk premium, and CAPM were all reasonable. In the Liberty case, the Commission relied upon Mr. Hevert's results and recommendation in arriving at a return on equity used for setting prospective rates. *Report and Order*, File No. GR-2014-0152 (Liberty Utilities), pp. 22-25. Mr. Hevert offers the same methodologies and overall approach in the instant proceeding, and his recommendation again provides the Commission with the most reasonable basis upon which to establish a return on equity.

In this case, Mr. Hevert begins his testimony by pointing out that foundational to a competent estimate of the cost of equity is a comprehensive review of relevant data, and that a reasonable ROE estimate "…appropriately considers alternative methodologies and the reasonableness of their individual and collective results in the context of observable relevant market information."[146] Mr. Hevert also introduces his group of "proxy" companies; companies he uses to establish a return that investors would require in order to invest in Ameren Missouri operations. A proxy group is necessary because Ameren Missouri is not publically traded.[147] Additionally, Mr. Hevert explains that "[a] significant benefit of using a proxy group is that it serves to moderate the effects of anomalous, temporary events associated with any one

[144] Ex. 16, p. 13, l. 20 to p. 14, l. 2.
[145] *Id.*, p. 31, l. 1 to p. 42, l. 2.
[146] Ex. 16, p. 7, l. 19-21.
[147] *Id.*, p. 8, l. 3-5.

company."[148] Mr. Hevert's Proxy group was developed using appropriate screening criteria to create a list of companies that provide a sound analytical basis upon which to conduct his DCF and CAPM models.[149]

a. *Mr. Hevert's DCF analysis.*

Mr. Hevert prepared a constant growth DCF analysis. This model measures investor expectations for the proxy group by developing the return expected as a product of annualized dividends and future growth. For the purposes of this model, the estimated growth remains constant in perpetuity.[150] Mr. Hevert calculated the expected returns by adjusting his model to correctly show the effects of dividends evenly distributed throughout the year, as a product of the quarterly payment of dividends.[151] Three separate sources of analysts' growth rates are used: Zacks, First Call, and Value Line.[152] Mr. Hevert used annualized dividends per share as of May 30, 2014, as a starting point for his analysis.[153] Mr. Hevert measured stock prices over three periods: 30, 90, and 180 days, and calculated mean low, mean and mean high results from his proxy group.[154] His results are summarized in the following tables from his Rebuttal Testimony:

[148] *Id.*, l. 6-8.
[149] *Id.*, p. 9, l. 7 to p. 10, l. 2.
[150] *Id.*, p. 16, l. 3-4.
[151] *Id.*, p. 15, l. 13-19.
[152] *Id.*, p. 18, l. 11-14.
[153] *Id.*, l. 8-18.
[154] Ex. 16, p. 19, l. 4-5, Schedule RBH-1.

Table 7a: Summary of DCF Model Results – Combined Proxy Group[155]

	Mean Low	Mean	Mean High
Constant Growth DCF Results			
30-Day Average	8.47%	9.44%	10.34%
90-Day Average	8.62%	9.58%	10.48%
180-Day Average	8.65%	9.62%	10.52%
Multi-Stage DCF Results			
30-Day Average	9.51%	9.77%	10.04%
90-Day Average	9.65%	9.92%	10.20%
180-Day Average	9.69%	9.96%	10.24%

Table 7b: Summary of DCF Model Results – Hevert Revised Proxy Group[156]

	Mean Low	Mean	Mean High
Constant Growth DCF Results			
30-Day Average	8.40%	9.32%	10.26%
90-Day Average	8.55%	9.48%	10.42%
180-Day Average	8.59%	9.51%	10.46%
Multi-Stage DCF Results			
30-Day Average	9.56%	9.81%	10.10%
90-Day Average	9.72%	9.98%	10.28%
180-Day Average	9.75%	10.01%	10.31%

[155] *See* Ex. 17, Schedules RBH-R7 and RBH-R8.
[156] *Id.*

As the tables demonstrate, the results change significantly depending upon the measurement period relied upon. At hearing, in response to Commissioners' questions, Mr. Hevert advises "considerable caution" in interpreting the DCF results in this case.[157] Mr. Hevert explained that the DCF model freezes the present elevated P/E ratios at a very high level.[158] During the time period the expert witness constant growth DCF models measured the cost of equity, the market was highly valuing the utility sector, and that sector was trading at a 10% premium to the overall market when historically a 10% discount would be the norm.[159] As a result, Mr. Hevert also noted that during the measurement periods used by the witnesses in this case, utility yields were moving down.[160] Prior to hearing, the opposite was occurring and yields were moving up "steeply." Mr. Hevert explained in Surrebuttal Testimony concerning unusually high valuations and observed that *Morningstar* had advised investors that utilities' stocks were trading nearly 10% above their intrinsic value and further observed that interest in short selling utility index funds had increased significantly.[161] Given that the constant growth DCF model assumes the inputs remain unchanged in perpetuity, the high valuation and low yield conditions are important to consider in assessing the output of this model in this particular case.[162]

Mr. Hevert also provides the result of a three-stage DCF analysis that models the change in utility earnings growth over time as market conditions change. This approach assumes investors anticipate change over the long term, rather than freezing in place present market conditions affecting the stock price and expectations for growth.[163] The model looks at three

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[157] Tr. p. 1169, l. 2-22.
[158] *Id.*
[159] Tr. p. 1166, l. 8 to p. 1167, l. 5.
[160] Tr. p. 1166, l. 5-7.
[161] Ex. 17, p. 17, l. 9-14.
[162] Tr. p. 1169, l. 2-22.
[163] Ex. 16, p. 20-21.

distinct phases of growth: near term, intermediate, and long term.[164] The model also allows for the calculation of the P/E ratio during each respective period.[165] The long-term growth rate is critical to the analysis as it contains the long-term growth in dividend and value of the investment being measured. Mr. Hevert calculated his long-term growth rate of 5.71% by taking a real GDP historic (1929-2013) value of 3.27 percent and combined it with an inflation calculation based on the spread between the long-term nominal Treasury securities and long term Treasury inflation protected securities of 2.37%. (Hevert Dir. pp. 22-23.)[166] This method is referred to as the "TIPS spread," and measures the delta between long-term nominal and inflation-protected rates to gauge investor expectations for long-term inflation.[167] Mr. Hevert uses Treasury securities that correspond with the long-term terminal growth (3rd stage) period.[168] In this manner, Mr. Hevert's model measures long-term growth as an expectation that growth in the investment will revert to its historic average plus inflation.[169]

The three-stage DCF model prepared by Mr. Hevert stands in contrast to those sponsored by the three other expert witnesses in that it measures investor expectations in a manner that recognizes a transition from the present conditions to a market that performs in a manner consistent with historic performance. Messrs. Gorman, Murray and Schafer all prepared a three-stage DCF that embodies a view that growth will never reach its historic norm, and instead turns sharply lower in the future. For example, Mr. Gorman relies upon a *projected* GDP equal to 4.60% that does not even correspond with the terminal period in the 3rd stage, and departs dramatically from historic experience.[170] As Mr. Hevert points out, Mr. Murray relies upon a

[164] *Id.*, p. 20, l. 13-14.
[165] *Id.*, p. 21, l. 8-14.
[166] *Id.*, p. 22, l. 4 to p. 23, l. 2.
[167] *Id.*
[168] *Id.*
[169] *Id.*
[170] Ex. 510, pp. 18-19; Tr. p. 1233, l. 13 to p. 1234, l. 7.

CAPM that uses historic market returns during a period that experienced an arithmetic average growth rate of 7.70%.[171] Mr. Gorman and Mr. Schafer provide a long-term growth rate similar to one used by Mr. Murray.

Mr. Hevert's three-stage DCF analysis (the results of which are shown in the tables above) also demonstrates a transition to normal historic dividend payout ratios over time (historic industry average of 67.05%),[172] again reflecting a transition from present market conditions to long-term expectations. This facet of the model is important given the caution that Mr. Hevert advises in this case regarding valuations. Incorporating a broader view that embodies a historic return to normal operation of the market over time, produces a range of three-stage DCF result that reflects investor expectations over time.

b. Mr. Hevert's ex ante capital asset pricing model.

A limitation of the two DCF models described above is that both attempt to measure investor expectations examining performance of only companies within the proxy group. Establishing a return on equity is a comparative analysis, and the CAPM models the return that diversified investors holding a portfolio would require given the many choices they have in the market.[173] The CAPM uses a "beta coefficient" to account for the difference in risk between a utility investment and the market as a whole.[174] Mr. Hevert explains the formula he uses for his CAPM analysis on p. 24 of his Direct Testimony. Essentially, the CAPM measures the overall market return, and applying the beta coefficients, develops a risk premium that is added to the assumed risk-free rate (30-year Treasuries). In recognition of the lower risk that the proxy

[171] Ex. 17, p. 39.
[172] Ex. 16, p. 23, l. 11-15 (Hevert Direct).
[173] Ex. 16, p. 25.
[174] *Id.*, p. 25, l. 9-11.

companies have to the overall market, the CAPM applies a beta coefficient to proportionally reduce the risk premium.

When calculated correctly, the CAPM provides a perspective that avoids the need to debate relative theories as to how economic growth constraints will affect the proxy group in the future, and instead measures return given comparative risk for the total market. Mr. Hevert's analysis is *ex ante*, or forward-looking.[175] This is a critical distinction between Mr. Hevert's approach and the approach used by the other three experts. Mr. Hevert prepared an all-market constant growth DCF for his proxy group to develop an overall market return. That analysis can be found in Schedule Nos. RBH-3 (from Ex. 16), and RBH-R9 (from Ex. 17). Mr. Hevert then applied *Bloomberg* and *Value Line* published beta coefficients to develop his risk premia applicable to the proxy companies.[176] His risk-free rate calculation was based upon a combination of the current 30-day average for Treasury yields and projected Treasury yields. Mr. Hevert assumed a risk-free rate for the purposes of his analysis is equal to 3.68%.[177]

The results of Mr. Hevert's analysis are contained on Table 7 of Mr. Hevert's Direct Testimony, and Tables 8a and 8b of his Rebuttal Testimony. Note that Mr. Hevert provides calculated results for both 30-day average and a near-term projected treasury yields. The Rebuttal tables are provided below:

[175] *Id.*, p. 26.
[176] *Id.*, p. 27, l. 6-7.
[177] Ex. 17, Table 8a, Table 8b.

Table 8a: Summary of CAPM Results – Combined Proxy Group[178]

	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (3.04%)	10.95%	10.39%
Near Term Projected 30-Year Treasury (3.68%)	11.59%	11.03%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (3.04%)	10.98%	10.42%
Near Term Projected 30-Year Treasury (3.68%)	11.62%	11.06%

Table 8b: Summary of CAPM Results – Hevert Revised Proxy Group[179]

	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (3.04%)	10.96%	10.40%
Near Term Projected 30-Year Treasury (3.68%)	11.60%	11.05%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (3.04%)	10.88%	10.33%
Near Term Projected 30-Year Treasury (3.68%)	11.52%	10.97%

c. Mr. Hevert's bond yield premium model and review of authorized returns.

Mr. Hevert also prepared a bond yield risk premium analysis. This model incorporates "…the basic financial tenet that equity investors bear the residual risk associated with ownership

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[178] *See* Ex. 17, Schedule RBH-R11.
[179] *Id.*

and therefore require a premium over the return they would have earned as a bondholder."[180] The bond rate that Mr. Hevert uses to develop his premium is the 30-year Treasury rate, and the risk premium is a function of authorized returns for electric utilities since 1980 (1,423 observations).[181] Mr. Hevert further observes that there exists a significant negative relationship between the 30-year Treasury and the risk premium.[182] Using a coefficient developed by a regression analysis that measures the relationship, Mr. Hevert measures the risk premium based upon the coefficients to develop an implied return on equity between 10.16 and 10.77.[183]

Mr. Hevert also provides evidence of recently authorized returns, including the most recent RRA report attached to his Surrebuttal Testimony as Schedule RBH-S1. The most recent Regulatory Research Associates ("RRA") report reflects that the authorized return on equity average for 2014 equaled 10.01% for vertically integrated utilities, and further demonstrates that Mr. Hevert's recommendation is far more consistent with authorized returns granted over the past 24 months than those of Messrs. Murray, Schafer, and Gorman.[184]

Mr. Hevert also provides the RRA Report for 2014, and further observed that Staff, OPC and intervenor recommendations were all below average allowed returns for less risky gas utilities, which averaged 9.78%.[185]

d. Business risk and capital market conditions.

With respect to the application and interpretation of the model results, Mr. Hevert provides a foundation for the development of a reasonable cost of equity. Mr. Hevert considered several facets of risk facing Ameren Missouri that distinguish it from other investments. The

[180] Ex. 16, p. 28, l. 5-7.
[181] Ex. 16, p. 29, l. 3-6.
[182] *Id.*, p. 30, l. 6-7.
[183] *Id.*, l. 9-11.
[184] In fact, as noted earlier, using the above-referenced 1,423 observations, Mr. Schafer's recommendation would be in the bottom 0.20th percentile, Mr. Murray's in the bottom 0.70th percentile, and Mr. Gorman's in the bottom 1.4th percentile. Ex. 18, p. 5, l. 1 to p. 6, l. 2; Schedule RBH-S29.
[185] *Id.*, p. 4, l. 11-12; Schedule RBH-S29.

regulatory environment is a significant factor to be considered in assessing risk.[186] Mr. Hevert observed that Missouri is only one of five states that legally prohibit utilities from including Construction Work in Progress in rate base.[187] Missouri also relies upon a historical test year and rarely allows interim rate increases.[188] Within this context, Mr. Hevert points out that the Company plans to invest over $3 billion in capital in its regulated operations from 2014 through 2018.[189] The lack of CWIP, an historical test year and extremely limited ability to seek interim rate relief will contribute to regulatory lag in recovering investments in the system, and creates significant uncertainty given that Ameren Missouri's high capital budgets will create a situation of negative free cash flows at the parent level.[190] As Mr. Hevert noted at hearing in response to Commissioner questions, cash flow is an extremely important risk factor considered by investors.[191] This regulatory risk, and its relationship to cash flows, is one reason that Mr. Hevert identified 10.4% as a point estimate for his cost of equity recommendation.

Mr. Hevert also identified the Company's generation portfolio as a risk factor to be considered. Coal-fired power represents the predominant majority (75%) of the Company's net generation, and nuclear energy also comprises a significant portion (20%) of the total.[192] The operation of coal-fired generation gives rise to risks associated with EPA compliance and new regulations on the horizon. As Mr. Hevert explains, compliance with existing regulations can require substantial capital investment (the Labadie ESPs are an example), and new regulations create the potential for substantial costs and uncertainty going forward.[193] With respect to the Callaway facility, Ameren Missouri is the owner of a single nuclear plant and does not have the

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[186] Ex. 16, p. 31, l. 13-14.
[187] *Id.*, p. 32, l. 15-16.
[188] *Id.*, p. 33, l. 3-16.
[189] *Id.*, l. 17-19.
[190] *Id.*, p. 33, l. 17 to p. 35, l. 4.
[191] Tr. p. 1158, l. 7 to p. 1161, l. 14.
[192] Ex. 16, p. 35, l. 7-10.
[193] *Id.*, p. 35, l. 17 to p. 36, l. 13.

benefit of economies of scale and diversity in operations when compared to companies that own several nuclear facilities, and Ameren Missouri has more risk for the special circumstances facing nuclear operators (i.e., the replacement of the reactor vessel head at Callaway) compared to utilities that do not have nuclear generation at all.[194]

Mr. Hevert also offered substantial testimony concerning capital market conditions. In his direct testimony, Mr. Hevert noted that the average Treasury rate since the Company's last rate case had increased.[195] Since the last rate case, Mr. Hevert observed that the Federal Reserve has begun tapering its asset purchases made under its Quantitative Easing policies.[196] That program was designed to put downward pressure on interest rates, and as the program unwinds and the economy improves, the inputs to the cost of equity models will increase, including growth rates and yields.[197] Moreover, Mr. Hevert indicated that market data is disjointed, and it is difficult to rely on a single model to estimate the Company's cost of equity.[198] During the case, Mr. Hevert observed and commented on elevated P/E ratios (also referred to as valuation levels), and explained that over time such valuation levels will revert to historic norms.[199] The high P/E ratios have a specific impact on DCF models, and Staff, OPC and intervenor experts rely heavily on those models. However, Mr. Hevert notes that the high P/E ratios are typically associated with high growth rates.[200] Mr. Hevert's argument makes logical sense, given investors might "price-in" the effects of anticipated investment growth. However, the same witnesses that base recommendations that assume P/E ratios will prevail essentially forever, also

[194] *Id.*, p. 36, l. 16-20.
[195] Ex. 16, p. 41, l. 3-6.
[196] *Id.*, p. 39, l. 6-7.
[197] *Id.*, p. 38, l. 17-20.
[198] *Id.*, p. l. 8-9.
[199] Ex. 18, p. 9, l. 3 to p. 10, l. 5.
[200] *Id.*, p. 18, l. 11-12.

do not argue that present growth rates expectations will increase – to the contrary, these parties argue they will turn down.[201]

In this case, a unique circumstance occurred as valuations moved toward historic norms prior to the hearing. At the hearing, Mr. Hevert noted that stock prices for the utility sector had traded down 10% from the previous month.[202] Dividend yield is a ratio that is the product of dividends divided by stock price, and when the value of stocks decreases, yields increase.[203] Mr. Hevert also observed that the dramatic fall in utility stock prices has been accompanied by a sharp increase in Treasury yields, equal to 50 basis points and dividend yields up 40 basis points.[204] At the hearing, Mr. Hevert further explained during questions from Commissioners, that he expects interest rates will rise and the Federal Reserve will decrease its intervention in the market.[205]

Mr. Hevert provides an array of results developed using different models to arrive at a reasonable range of returns, and supports a return on equity between 10.2% and 10.6%. His analysis also takes into account relevant business and regulatory risk considerations in arriving at his 10.4% point estimate. Mr. Hevert's assessment is based upon methods recently found by this Commission to be reasonable for the measurement of the cost of equity and provide a strong evidentiary foundation for a return that meets the ***Bluefield*** and ***Hope*** standards.

A complete summary of Mr. Hevert's analytical results (constant growth DCF, multi-stage DCF, CAPM, and bond yield risk premium) as updated at the time of his rebuttal testimony (January 16, 2015) can be found in the tables above.

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[201] *Id.*, l. 12-17.
[202] Tr. p. 1153, l. 1-4.
[203] Tr. p. 1192, l. 21 to p. 1193, l. 3.
[204] Tr. p. 1153, l. 14-18.
[205] Tr. p. 1170-1171.

ii. Analysis of Mr. Gorman.

Mr. Gorman filed testimony on behalf of MIEC and advocates setting rates using a cost of equity equal to 9.3%, with a range of results between 9.0% and 9.6%.[206] When taking into consideration other utility authorized returns, Mr. Gorman testified investors would expect a return equal to 9.63%.[207] Mr. Gorman uses a DCF, bond yield risk premium, and CAPM to establish his range of return recommendations. He calculates one number for each method and selected the mid-point for his point estimate recommendation of 9.3.[208] Mr. Gorman did not meaningfully update any of his analytical results in his rebuttal or surrebuttal testimony, with the exception of a change in position based upon his limited view of authorized returns as noted above.[209]

a. MIEC's claims regarding capital markets.

Mr. Gorman argues his recommendation is justifiable due to lower capital market costs.[210] However, at hearing, Mr. Gorman reluctantly admitted that the risk-free rate base based on Treasuries as an input into his CAPM is higher today that it was in Ameren Missouri's last rate case.[211] Mr. Gorman also agreed that the analyst growth rates that he relies upon are higher this case than in the last case.[212] Based upon comments made by the Federal Reserve, improvements in unemployment rates, and strong growth, Mr. Gorman agrees that the economy has been improving over the past 24 months.[213]

[206] Ex. 510, p. 2, l. 4-6.
[207] Ex. 512, l. 7-11 (Gorman Surrebuttal).
[208] Ex. 510, p. 38, l. 2-6.
[209] Ex. 512, l. 7-11.
[210] *Id.*, p. 9, l. 18-21.
[211] Tr. p. 1218, l. 2-7.
[212] Tr. p. 1221, l. 2-8.
[213] Tr. p. 1221, l. 22 to p. 1222, l. 4.

Furthermore, Mr. Gorman also claims that a utility construction cycle has a positive impact on its earnings growth, a component of his DCF analysis.[214] At hearing, Mr. Gorman readily admitted that utilities throughout the United States are making investments to replace aging infrastructure and that such a condition represents an industry-wide phenomenon.[215] He also acknowledged that current and prospective environmental regulations require substantial capital investment for vertically integrated utilities like Ameren Missouri.[216] Mr. Gorman attempted to show that Moody's average bond yields, an industry index, showed a declining trend in costs. However, an updated analysis indicated that rates have recently pivoted and increased.[217] This clearly coincided with the 50-basis point increase in Treasury rates that Mr. Hevert identified at hearing.

Thus, setting aside interest rates, growth rate trends, and general economic conditions, the declining capital market conditions to which Mr. Gorman alludes are elusive. Rather than *conditions* in a plural sense, Mr. Gorman focuses on one singular input into his DCF models to support this changing market dynamic contention: dividend yields. Mr. Gorman posits that "[high] P/E ratios also correspond to very low dividend yields, which are an indication of a reductions to utilities' cost of capital."[218] Mr. Gorman goes on to argue that "[w]hile Mr. Hevert….may have opinions that capital market costs will increase sometime in the future, increasing capital costs and the timing of when the increase will occur are highly uncertain…"[219] Clearly, Mr. Gorman seeks to highlight the low dividend yields captured his analysis by virtue of the high valuation and P/E ratios contained in the 13-week stock price average used to calculate

[214] Ex. 510, p. 21, l. 4-14.
[215] Tr. p. 1213, l. 18-25.
[216] Tr. p. 1212, l. 1-6.
[217] Ex. 62.
[218] Ex. 512, p. 9, l. 7-8.
[219] *Id.*, l. 11-14.

his DCF results. However, rather than being highly uncertain as to when dividend yields will rise and stock valuations will come down, the record shows that such a phenomenon actually started occurring in a substantial way just prior to hearing. As noted above, both Mr. Hevert and Mr. Schafer acknowledge the sudden and significant decline in stock valuations.[220]

b. Mr. Gorman's DCF results.

Mr. Gorman utilizes three types of discounted cash flow models to support his recommendation: a constant growth DCF, a sustainable growth DCF, and three-stage DCF.[221] The DCF results constitute the bottom of Mr. Gorman's range of reasonable returns. Of those three methods, two of them contain growth rates that contain a subjective measure of what Mr. Gorman believes to be "sustainable." These two methods, the "sustainable" growth DCF and the three-stage DCF, present staggeringly low implied returns of 8.71% and 8.57% respectively.[222]

Mr. Gorman's constant growth DCF result of 8.95% relies solely upon a single 13-week average stock price, and he offers no other measurement periods or perspectives. As noted above, Mr. Gorman's measurement of the stock price contains a very limited view.
Given the volatility and uncertainty with respect to the valuation of utility stocks as discussed at hearing, Mr. Gorman's constant growth rate should be viewed with great suspicion. Further, while Mr. Gorman claims that high stock valuations and low dividend yields will continue indefinitely, he fails to offer any evidence to explain what fundamentals underlying the market have changed such that historic normal P/E ratios are no longer anticipated by investors when they make investment choices.

[220] Tr. p. 1153, l. 1-8; Tr. p. 1316, l. 5-12.
[221] Ex. 510, pp. 18-25.
[222] Ex. 510, p. 26, Table 2.

Mr. Hevert explains that stock P/E ratios are likely to return to normal levels closer to multiples of 17, from recent valuation multiples ranging between 19 and 21.[223] The high stock valuation pushes dividend yields below what Mr. Schafer observed as a historic norm of approximately 4.5%.[224] Mr. Gorman's constant growth DCF relies upon a dividend yield of 3.7% and 3.9% on an adjusted basis.[225] Further, market activity immediately preceding the hearing demonstrated that point, with the utility sector trading 10% lower over a very short period. Accordingly, the evidence sustains a conclusion that Mr. Gorman's DCF model is producing unreliable results.

An equity investment is a long-duration investment, and it should be measured as such.[226] Accordingly, it is critical that the return on equity incorporate a broader understanding of market conditions and that temporary aberrations in price affected by short-term investor activity not form the basis of measuring the cost of equity. It thus follows that Mr. Gorman's constant growth DCF results should not be relied upon as an accurate measure of the cost of equity.

Because the three-stage DCF allows for a modeling of the transition of present constant growth DCF assumptions to long-term expectations concerning an investment, it offers an opportunity to address deficiencies in a constant growth model. However, Mr. Gorman's model takes the analysis in the wrong direction. As the evidence demonstrates, Mr. Gorman predicts a sharp downturn in growth rates. However, Mr. Gorman fails to substantiate these claims with clear evidence that investors would actually anticipate that in the future growth will dramatically decline as a long-term proposition. Simply put, Mr. Gorman's long term expectations are too low at 4.4%.

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[223] Ex. 18, p. 8, l. 9-18; p. 9, Chart 3; Tr. p. 1168, l. 2-24.
[224] Tr. p. 1314, l. 22 to p. 1315, l. 1.
[225] Ex. 510, Schedule MPG-4; the 3.7% figure is calculated using data from Schedule MPG-4 ($1.58/$42.80).
[226] *Id.*, p. 34, l. 3-10 (explaining why a 30-year bond has an appropriate term when valuing an equity investment).

The frailties of Mr. Gorman's long term growth rate assumptions are many. First, Mr. Gorman claims that in the next three to five years, when the utility construction cycle will be "…completed or levels off," growth will be less.[227] He offers no evidentiary support for the claim that utility construction will be "completed" or will "level off." Mr. Gorman made the same specific observation in 2008, yet today, in this case, Ameren Missouri has clearly included substantial capital additions to rate base – in fact, such additions drive the revenue requirement increase requested.[228] The assumption that construction will be "completed" or "level off" is a major assumption that drives Mr. Gorman's three-stage DCF results, and it is important to consider the lack of support for that assumption.

Furthermore, Mr. Gorman's five-year analyst growth rates have consistently exceeded his long-term growth rate assumptions.[229] In each Ameren Missouri case since 2007, the analyst growth rates have been consistent with or higher than Mr. Gorman's assumed long-term growth rate.[230] He readily admits he relies on those higher analyst growth rate assumptions, and more importantly, that investors would consider the same sources.[231] Mr. Gorman also identifies a publication, Blue Chip Economic Indicators, as his source for his long-term growth rate – a nominal GDP estimate.[232] His long-term growth rate is intended to begin "…starting in year 11 through perpetuity."[233] However, the source of his information only provides predictions through years five through ten, and offers no additional predictions from that point forward.[234] Mr. Gorman uses mismatching data to determine a *perpetual explanation of growth.* Additionally, the Blue Chip document also reports projected corporate profits, a function of

[227] Ex. 510, p. 21, l. 7-10.
[228] Tr. p. 1227, l, 5. To p. 1229, l. 6.
[229] Tr. p. 1230, l. 11-20.
[230] *Id.*
[231] Tr. p. 1219, l. 11 to p. 1220, l. 24.
[232] Tr. p. 1231, l. 21 to p. 1232, l. 3; Ex. 63.
[233] Ex. 510, p. 22, l. 1-2.
[234] Ex. 63.

earnings growth, occurring at a rate higher than projected nominal GDP for the same period.[235] This presents an inherent conflict in the data presented: If earnings growth rates are not sustainable because they are higher than Blue Chip's projected 10 year growth, then it is unclear how U.S. corporate profits can sustain such growth considering Mr. Gorman's view. The Blue Chip's Economic Indicators warn us as follows: *"Apply these projections cautiously. For the most part economic and political forces over such long time spans cannot be evaluated with accuracy*."[236] The statement is clear: the projections should be viewed in a broader context and in light of other variables, and not with the deterministic view that Mr. Gorman's analysis indicates. The Commission should take the Blue Chip caution under consideration, and take a broader view of long-term growth expectations.

Mr. Gorman also offers what is called a "sustainable growth DCF." The Commission has previously rejected this approach as presenting growth rates that are too low.[237] The Commission should do the same in this docket. Mr. Gorman's sustainable growth DCF presents an unsustainably low growth expectation that is significantly at odds with the consensus analyst expectations Mr. Gorman cites (5.05%).[238] Mr. Gorman admits that investors would find the source (Zack's, SNL, and Reuters) of his analyst growth rates reliable, but offers no such evidence with respect to his "sustainable model growth rate of 4.77%."[239] The Commission has not accepted this model in the past, and should decline to do so in the instant case.

[235] Tr. p. 1237, l. 12 to p. 1238, l. 2.
[236] Ex. 63.
[237] *Report and Order*, File No. ER-2011-0028, pp. 71-72.
[238] Ex. 510, p. 18, l. 12-13.
[239] Ex. 510, p. 20, l. 10-11.

c. Mr. Gorman's bond yield risk premium.

In his direct testimony, Mr. Gorman offered a bond yield risk premium analysis that "throw out the three highest and three lowest" risk premiums to calculate his analysis.[240] The Commission has previously found this analysis to be flawed due to the selective exclusion of certain data.[241] Nothing in the record demonstrates that the facts have changed or the Commission's criticisms are invalid, and thus this methodology should not be considered. In lieu thereof, Mr. Gorman changed his methodology in his rebuttal testimony in a manner that he argues supports his return on equity ratio through the use of what Mr. Gorman refers to has a "rolling average."[242] Conveniently, the "rolling average" produces a risk premium that is even below what the Commission criticized for being too low in the last case.[243] Analysis should not be prepared after the fact to rationalize the preconceived result, rather the result should be a product of informed and reasoned analysis. There is no reason presented in this case for the Commission to change course with respect to its consideration of Mr. Gorman's flawed bond yield risk premium approach, as modified or otherwise.

d. Mr. Gorman's CAPM results.

Mr. Gorman relies in part on the product of his CAPM, which he calculates as producing a result of 9.24%. Mr. Gorman's model is inaccurate for one fundamental reason: it mixes historic information in a manner unadjusted and thus inappropriately applied to near-term current and prospective data. He takes a backward looking view to develop his risk premium that relies on a total market return since 1926.[244] Mr. Gorman then plucks spot beta coefficients that measure the returns for the proxy group relative to the overall market from three dates in 2014,

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[240] Ex. 511, p. 16, l. 9-10.
[241] *Report and Order*, File No. ER-2002-0160, pp. 70-71.
[242] *Id.*
[243] *Id.*, Schedule MPG-R-3.
[244] Ex. 510, p. 34, l. 20 to p. 35, l. 20.

and combines that with a projected Treasury rate of 4.1%.[245] Note that Mr. Gorman's risk premium is developed during a time he indicates the Treasury rate was 5.9% on average,[246] but applies his premium to a far lower 4.10% projected rate.[247] Unlike Mr. Hevert, Mr. Gorman makes no effort to understand the relationship in formulating his risk premium he presented in his direct testimony.[248]

Mr. Gorman's approach contradicts his arguments concerning his DCF results. Additionally, with respect to yields and growth rates, Mr. Gorman argues that changed financial conditions dictate a lower cost of capital. Thus, it is logically irreconcilable that Mr. Gorman would reject Mr. Hevert's *ex ante* (forward looking) approach in favor of a historical approach to developing a risk premium. As Mr. Hevert explains in detail, the relationship between Treasury rates and the risk premium is not static.[249] Mr. Hevert's *ex ante* approach dispenses with the need to reconcile historical data, by taking present analyst growth rates from two sources, uses a combined recent historic and projected Treasury average, and contemporary beta coefficients to develop a forward looking view.

e. Mr. Gorman's analysis of authorized returns.

In his Surrebuttal Testimony, Mr. Gorman notes that recognizing authorized rates of return would indicate investor expectations consistent with 9.63%.[250] However, closer review indicates that the value that Mr. Gorman holds out as an applicable average return is not properly calculated.[251] He includes utilities that do not have comparable business risk, and excludes

[245] Ex. 510, p. 33, l. 20-21.
[246] *Id.*, p. 35, l. 17-18.
[247] *Id.*, p. 33, l. 18-19.
[248] Ex. 17, p. 111, l. 1-11.
[249] Ex. 16, p. 30, Chart 1.
[250] Ex. 512, p. 4, l. 11.
[251] *Id.*, Schedule MPG-SR-1; Tr. p. 1238, l. 16-19.

unnecessarily returns that were duly approved by Commissions pursuant to a settlement.[252] He reports the results of vertically integrated utilities, but does not rely upon those results to assist him in gauging investor expectations.[253]

Mr. Gorman improperly includes distribution utilities or "wires only" companies in his average. He admits that such utilities do not have the same risks as companies that own generation.[254] When presented with a recent credit report prepared by Moody's Investors Services concerning Ameren Missouri,[255] Mr. Gorman agreed that the risks posed by environmental regulation of carbon were a concern to Moody's, and that wires only companies would not have such a risk.[256] Mr. Gorman agreed that investors, specifically institutional investors, would want to review the Moody's report in making an investment decision.[257]

Mr. Gorman bases his analysis on a very limited subset of authorized returns for electric utilities. Specifically, Mr. Gorman reviews only ROEs from litigated cases.[258] However, at hearing Mr. Gorman admitted that two of the companies are Illinois distribution-only electric utilities (Ameren Illinois and Commonwealth Edison), and the returns in those proceedings were not litigated because they were derived through the operation of a formulaic calculation.[259] In fact, Mr. Gorman indicated that with respect to those utilities, there is nothing to litigate because the value is clearly defined.[260] Both companies are participants in a formula rate plan pursuant to Illinois Energy Infrastructure Investment Act.[261] The inclusion of these two returns is inappropriate as they are wires only companies and participants in a unique formulaic rate plan.

[252] *Id.*, p. 3, l. 17-23; Schedule MPG-SR-1.
[253] *Id.*
[254] Tr. p. 1241, l. 9-13.
[255] Ex. 61.
[256] Tr. p. 1243, l. 3-11.
[257] Tr. p. 1242, l. 11-18.
[258] Ex. 512, p. 3, l. 19 to p. 4, l. 4; Schedule MPG-SR-1.
[259] Tr. p. 1244, l. 16-19; Tr. p. 1245, l. 3-13.
[260] Tr. p. 1246, l. 3-10.
[261] Tr. p. 1244, l. 23 to p. 1245, l. 5.

Setting aside the problems with excluding settled returns discussed below, the inclusion is also illogical if the intent is to reflect only litigated returns. If these two companies were removed, Mr. Gorman admitted the average upon which he relies to gauge investor expectations (9.63%) would be higher.[262]

Mr. Gorman himself testified in two recent cases whereby his clients signed onto stipulated agreements that included a stated return on equity of 9.83% and 9.8%, respectively.[263] (In the most recent case in February, 2015, Mr. Gorman testified he advised his client that the settlement was reasonable and his client agreed. (Tr. 1249). That settlement included a 9.83% return on equity for a vertically integrated utility and a 56% equity ratio in its capital structure. The Company also had a fuel adjustment mechanism, a special rider for recovery of qualifying investments, and was allowed by law to recover CWIP in rates.[264]

Accordingly, Mr. Gorman's 9.63% estimation of an average return on equity is too low - it includes returns for companies that have different risks than Ameren Missouri, and unnecessarily excludes other appropriate data.

iii. Analysis of Mr. Schafer's ROE recommendation.

OPC witness Lance Schafer recommended a return on equity of 9.01%.[265] This proceeding is the first regulatory proceeding in which Mr. Schafer has testified.[266] Mr. Schafer is working on, but has not yet received, the Chartered Financial Analyst designation.[267] Mr. Schafer has not worked as a financial analyst, at a bank, in a corporate treasury department, as a broker or trader, nor has he otherwise ever been involved with the issuing of debt or equity.[268]

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[262] Tr. p. 1246, l. 24 to p. 1247, l. 4.
[263] Tr. p. 1247, l. 5-8; Tr. p. 1248, l. 1-4; Tr. p. 1249, l. 10-14; 23-25.
[264] Tr. p. 1247, l. 5 to p. 1249, l. 9.
[265] Ex. 409, p. 3, l. 14.
[266] Tr. p. 1309, l. 4-6.
[267] *Id.*, l. 22-25.
[268] Tr. p. 1310, l. 3-20.

The Company fully recognizes that an expert witness has to begin at some point, and does not intend to denigrate Mr. Shafer in this regard. However, at this juncture, Mr. Schafer's limited experience indicates his analysis is academic in nature, and these facts should impact the weight to be accorded to it. Mr. Schafer has presented a return recommendation that is one-basis point higher than a return of 9% that the Commission found to be unreasonably low in Ameren Missouri's last rate case.[269]

Mr. Schafer's recommendation is low due to the inclusion of very low yield and growth assumptions, a lack of appropriate consideration for returns authorized in other jurisdictions, and the improper calculation and consideration of his CAPM results. Many aspects of Mr. Schafer's DCF and CAPM are very similar to Mr. Gorman's and accordingly the criticisms will not be repeated below for the sake of brevity.

a. Mr. Schafer's DCF analysis.

Mr. Schafer's constant growth DCF calculation includes a dividend yield of 3.5%. Mr. Schafer readily admits that historically, utility yields are equal to approximately 4.5% and that the historic rate for the proxy group is 4.37%.[270] Mr. Schafer agreed that Value Line (a source Mr. Schafer relies upon) projects an average 4.44% dividend yield for his proxy companies.[271] Mr. Schafer agreed these sources are reliable and that utility investors would consider these sources when making investment decisions.[272] The difference between Mr. Schafer's yields and the norm is thus about 100-basis points or 1% (4.5 - 3.5% = 1.00%). Mr. Schafer attempts to remedy this 100-basis point anomaly in his calculation with a 45-basis point adjustment.[273] Mr. Schafer's 45-basis point solution to a 100-basis point problem is indicative of a flawed analysis.

[269] *Report and Order*, File No. ER-2012-0166, pp. 68-69.
[270] Tr. p. 1314, l. 22 to p. 1315, l. 5.
[271] Tr. p. 1315, l. 6-9.
[272] Tr. p. 1310, l. 21 to p. 1311, l. 10.
[273] Ex. 409, p. 21, l. 18-19.

Consider the impact of an additional 55-basis points on Mr. Schafer's 9.22 constant growth DCF results if he models the historic norm (an implied value of 9.77). Mr. Schafer also recognizes the impact of high utility valuations on yields.[274] Mr. Schafer further acknowledges that he agreed that utility industry stocks have traded down 5-10%, corroborating Mr. Hevert's hearing testimony.[275] Mr. Schafer also agreed that the trade-off could have resulted from sector rotation, where investors move out of specific industries depending on how they perceive future economic conditions.[276] Accordingly, Mr. Schafer's constant growth DCF model should be viewed with caution, as it contains data that is inconsistent with historic experience for the utility sector and projections relied upon by investors, and appears to be affected by short-term trading actions of investors.

Similar to Mr. Gorman, Mr. Schafer also relies upon a GDP projection that is lower than current growth estimates in order to support a position that going forward investors expect less growth. This approach results in the extremely low implied return of 8.62%.[277] The perils of relying upon limited forecasts of GDP growth as the basis for growth assumptions has already been argued above and need not be restated here. One point of note is that Mr. Schafer's estimate is significantly higher than Mr. Gorman's, illustrating the divergence of expectations with respect to future U.S. GDP growth. Departing from Mr. Gorman's approach, Mr. Schafer considered a number of sources to derive his own unique modeling of GDP that included information from several government agencies, publications, and websites.[278] This simply is Mr. Schafer's own combination of data from various sources. There is no basis to conclude that

[274] Tr. p. 1316, l. 17-20.
[275] Tr. p. 1316, l. 9-12.
[276] Tr. p. 1317, l. 21 to p. 1318, l. 7.
[277] Ex. 409, p. 26, l. 18.
[278] *Id.*, p. 25, l. 5 to p. 26, l. 9.

individual investors would interpret this information the same and then proceed to rely upon this method to ascertain future constraints on proxy company growth.

b. Mr. Schafer's CAPM analysis.

Mr. Schafer prepared a CAPM analysis in this case, that, similar to Mr. Gorman's, contains both long-term historic data for years between 1926 and 2013, and combines that with near term Treasury yield projections and current beta estimates.[279] The fundamental problems with this approach are discussed above and need not be restated here. At hearing, Mr. Schafer indicated that during the time period which Mr. Schafer reviewed, 1947-present, he concluded that historic U.S. GDP was approximately 6.3%.[280] Yet Mr. Schafer then matches the historic risk premium to a complicated calculation of projected Treasury rates at 4.5% that he holds out as the applicable risk-free rate.[281] Mr. Schafer does not consider the relationship between the market risk premium and the risk-free rate, but instead simply criticizes Mr. Hevert's approach as "exaggerated."[282] Mr. Schafer does not identify any mistaken or errant data in Mr. Hevert's ex ante CAPM. Mr. Schafer criticizes Mr. Hevert's use of Treasury rates, but Mr. Hevert unequivocally shows 16 calculations of his CAPM using two sources of market risk premiums, two sources of beta coefficients, and two separate measurements of the risk-free rate.[283] Rather, Mr. Schafer primarily criticizes Mr. Hevert's CAPM growth by claiming (without support) that it cannot be "sustained."

Mr. Schafer's criticism, in essence, conflates the issues of *sustainability* with respect to a DCF model with an entirely different model. The DCF model only looks at the proxy utility companies in terms of growth rates, but the CAPM takes a broader view of growth and

[279] *Id.*, p. 34, l. 13 to p. 35, l. 18; Schedule LCS-9.
[280] Tr. p. 1312, l. 13-18.
[281] Ex. 409, p. 29, l. 10-11.
[282] Ex. 410, p. 40, l. 1-5 (Schafer Rebuttal).
[283] Ex. 17, p. 123, Table 8a, Table 8b.

investment alternatives with the broader view *of the entire market* that the CAPM models. As Mr. Schafer agreed at hearing, the market risk premium he developed includes the S&P 500 or the NYSE, and Mr. Schafer readily agrees the marketplace for capital is today global.[284] The growth rates incorporated in the S&P 500 that Mr. Hevert uses are the sum of consensus analyst forecasted growth rates published by Bloomberg and Value Line.[285] The CAPM is intended to measure the return of the companies (proxy group in this case) to the market as a whole, and the beta coefficient accomplishes this end.[286] Within the total market measured in the CAPM, Mr. Schafer agrees it is not uncommon to find companies experiencing higher growth than U.S. GDP, and not hard to find growth rates of 12%, 13%, or 14%.[287] He also agreed many companies listed in the S&P 500 are multi-national.[288]

Thus, when considering what is sustainable with respect to the CAPM, the standard is much different than the standard upon which one would estimate constraints to growth for utility proxy companies. Mr. Schafer's own source published by Morningstar, calculated an arithmetic average market return of 12.1 or 12.2%.[289] This value is not much lower than Mr. Hevert's Value Line market return of 12.75%.[290] As Mr. Hevert noted, his expected market return essentially is statistically indistinguishable from the long-term average on which Mr. Schafer relies.[291] Mr. Schafer's own source lists an arithmetic average all market return only 55 to 65-basis points lower than Mr. Hevert, yet his CAPM result of 8.74% is at least 159-basis points lower than Mr. Hevert's.

[284] Tr. p. 1320, l. 12-15; Tr. p. 1325, l. 9-11.
[285] Ex. 17, p. 122, l. 2-10.
[286] *Id.*
[287] Tr. p. 1321, l. 11-15.
[288] Tr. p. 1322, l. 20-23.
[289] Tr. p. 1325, l. 19 to p. 1326, l. 1.
[290] Ex. 17, p. 123, Table 8b; Schedule RBH-R9.
[291] Ex. 18, p. 31, l. 15-16.

Additionally, Mr. Schafer testified that in two instances, he confirmed the existence of an inverse relationship during specific periods of time.[292] Mr. Hevert's testimony illustrates plainly the inverse relationship between the risk premium and interest rates.[293] Moreover, Mr. Hevert explains in common sense terms why this relationship occurs, as follows: "as investors seek the safety of Treasury securities they require higher equity returns to overcome the perceived risk of equity markets vis-à-vis Treasury securities."[294] Moreover, Mr. Hevert explains the effect of market intervention by the Federal Reserve on this dynamic, observing that "…uncertainty surrounding the timing and degree of future intervention introduces an additional element of uncertainty, which increases investment risk, and therefore the required return."[295] While Mr. Schafer and OPC would like to ignore the dynamic and inverse relationship between Treasuries and the risk premium, this relationship is salient to the consideration of the current cost of equity, particularly in an era of market intervention by central banks. The *ex ante* approach used by Mr. Hevert is superior in this regard, and should be accorded appropriate weight by the Commission.

c. Mr. Schafer's arguments concerning authorized returns.

Mr. Schafer minimizes the importance of authorized returns for vertically integrated utilities in other jurisdictions.[296] In Mr. Schafer's opinion, authorized returns in other jurisdictions for similarly situated utilities are not "…a strong indicator of what the correct outcome should be in this case."[297] Mr. Schafer ignores the past practice of this Commission, and salient requirements of ***Bluefield*** and ***Hope*** to establish a return opportunity commensurate

[292] Ex. 410, p. 53, l. 10-11.
[293] Ex. 18, p. 32, Chart 5a; p. 33, Chart 5b.
[294] *Id.*, p. 33, l. 4-6.
[295] *Id.*, l. 9-11.
[296] Ex. 411, p. 6-7.
[297] Ex. 411, p.7, l. 7-8.

with other businesses of similar risk. Capital markets are competitive, and returns must be competitive.

Infrastructure investment is important and the Commission cannot decide ROE in a regulatory vacuum. Checking the reasonableness of a recommendation by reference to authorized returns is valid and important to ensure the competitiveness of Ameren Missouri. Mr. Schafer's failure to take seriously this important consideration as part of his analysis is a critical weakness in his approach.

iv. *Analysis of Mr. Murray.*

Mr. Murray's recommendation and methodologies are difficult to follow or make sense of in this case. At hearing, Mr. Murray indicated he had forgotten a section of the Staff Report filed in the case, and also made corrections to numerous numbers contained in his testimony and exhibits.[298] The corrections and the reasons for them are hard to follow. This necessitates the parties and the Commission to rely upon Mr. Murray's reassurance that the litany of corrections has no effect on his underlying recommendation. Corrections to testimony are normal and appropriate in most instances. However, when last minute additions and corrections are pervasive and include entire sections of substantive material, this is an indication that the underlying analysis may not be reliable, and accordingly the Commission should accord appropriate consideration of this fact when weighing the evidence.

Mr. Murray's position in this case is plagued by logical inconsistencies. Mr. Murray tells the Commission capital markets have declined for Ameren Missouri since its last rate case.[299] Yet, Mr. Murray's recommendation has increased from his position advocated in that case.[300] Mr. Murray admits he is not recommending the Commission approve a return on equity equal to

[298] Tr. p. 1335, l. 7-21; Tr. p. 1336, l. 1-7; Tr. p. 1337, l. 8 to p. 1339, l. 18; Ex. 245.
[299] Tr. p. 1345, l. 5-8
[300] Tr. p. 1345, l. 20 to p. 1346, l. 4.

what he actually claims the cost of equity to be.[301] Mr. Murray claims that Ameren Missouri's cost of equity is substantially less than 9.25% and that instead the actual cost of equity for utilities is between 6% and 8%, and closer to 6%.[302] Mr. Murray agrees that if the Commission were to establish a return on equity equal to 6%, that investment analysts would view this as a negative development.[303] Consider this point: Mr. Murray is telling the Commission that if it sets the return on equity at an amount equal to what he claims the true cost of equity is, which is *a competitive market driven cost*, investors would view this as a negative development. Mr. Murray cannot identify an authorized return ever granted in any jurisdiction between 6% and 8%.[304] Mr. Murray agrees that he does not believe this Commission would approve an ROE consistent with what he claims the true cost of equity is.[305]

In the last Ameren Missouri rate case, the Commission observed that "[e]ven Murray does not believe the Commission will actually award an ROE of 9.0% based on his recommendation. Instead, he is trying to convince the Commission to award an ROE below 10.0%."[306] Mr. Murray attempts the same approach in this case, and the same result should be accorded.

Mr. Murray's methodologies with respect to the measurement of equity in terms of his DCF and CAPM are very similar to Mr. Schafer's and Mr. Gorman's, and there is no need to repeat those arguments. The difference between Mr. Murray and MIEC and OPC is primarily the degree to which Mr. Murray's assumptions drive the cost of equity measurement down. If Mr. Gorman and Mr. Schafer can be characterized as *pessimistic* in their assumptions, Mr.

[301] Tr. p. 1346, l. 13-16.
[302] Tr. p. 1348, l. 8-13.
[303] *Id.*, l. 14-18.
[304] Tr. p. 1349, l. 8-12.
[305] Tr. p. 1361, l. 10-18.
[306] *Report and Order*, File No. ER-2012-0166, p. 69.

Murray's assumptions are *fatalistic*. Mr. Murray also introduces methods not used by the other witnesses, including the "rule of thumb" and his use of special purpose financial reports, including those relating to Ameren Missouri's parent. The Commission has not accepted these methods previously, and there is no justification to change that course in this case. In the 2011 Ameren Missouri rate case, Mr. Murray attempted to persuade the Commission by using study published by Mergent and select Goldman Sachs data to support very low growth rates (similar to the growth rates he uses in this case).[307] The Commission found that Mr. Murray improperly relied on analysis prepared for purposes distinct from ratemaking.[308] Again, there is no reason to question the salience of the Commission's previous findings in this case.

Mr. Murray agrees that his recommended returns are routinely found to be too low and routinely below the national average.[309] He claims that pervasively throughout the United States, Commissions, including the Missouri Commission, are hesitant to recognize what he alone claims is the true cost of equity.[310] He further claims that to the extent Commissions set a return on equity above 9%, those jurisdictions *are wrong* if they believe the ROE being approved is consistent with what the true cost of equity is.[311] This is a significant theme in Mr. Murray's analysis – a paradox between the truth and reality when it comes to how equity is valued. Mr. Murray claims he himself has identified the truth, and everyone else is simply wrong. The problem is that the question of what the true cost of equity is, is not a function of what Mr. Murray's personal claims or beliefs are, but rather derives from a rational interpretation of

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[307] *Report and Order*, File No. ER-2011-0028, pp. 69-70.
[308] *Id.*, p. 70.
[309] Tr. p. 1355, l. 23 to p. 1356, l. 5.
[310] *Id.*, l. 6-11.
[311] *Id.*, l. 12-17.

market data that defines what investors expect and require in order to invest.[312] Mr. Murray agrees readily that investors consider returns authorized by this and other jurisdictions.[313]

For Mr. Murray's constant growth DCF analysis, he references growth rates of 5.74% and 5.6% for his proxy group.[314] Mr. Murray identified SNL financial as the source of these growth rates.[315] Mr. Murray agrees SNL is recognized as an authoritative source in the finance industry and investors would consider this information when making investment choices.[316] However, unlike Mr. Gorman, Mr. Schafer and Mr. Hevert, Mr. Murray does not use analyst growth rates in his constant growth DCF analysis. Instead he substitutes 3.5%.[317] With respect to his multi-stage DCF, Mr. Murray uses a similar growth rate.[318] However, Mr. Murray claims that this is not the actual, long-term growth rate. Instead Mr. Murray claims that the growth rates are actually between 2 and 2.5%[319] Mr. Murray contends that investors purchasing a stock today would expect no real capital appreciation over the long-term.[320] Mr. Murray has been criticized by the Commission in the past for his unreasonably low growth rates.[321] In this case, Mr. Murray employs the same methodology and perspectives on growth. The Commission was correct in 2010, and that continues to be the case today – Mr. Murray's growth rates for his DCF models are unreasonably low. In this case, Mr. Murray's growth rates are the lowest of any of the ROE witnesses, and should not be considered in formulating the Commission's decision.

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[312] Ex. 16, p. 4, l. 5-6.
[313] Tr. p. 1356, l. 18-21.
[314] Tr. p. 1350, l. 9-16.
[315] *Id.*, l. 17 to p. 1351, l. 2.
[316] *Id.*, l. 14-18.
[317] Tr. p. 1351, l. 23 to p. 1353, l. 1.
[318] Tr. 1359, l. 20 to p. 1360, l. 2.
[319] Tr. p. 1360, l. 3-1.
[320] Tr. p. 1360, l. 22 to p. 1361, l. 9.
[321] *Report and Order*, File No. ER-2010-0036, pp. 18-19.

Mr. Murray has admitted that if we consider other authorized returns, investors would expect at least a 9.5% return.[322] Setting aside the problems with Mr. Murray's underlying analysis, the recognition that investors do consider other authorized returns and that capital markets are competitive, is an admission that the return on equity that is required to induce investment is much higher than 6-8%, and much higher than Staff's 9.25% point estimate.

VII. FUEL ADJUSTMENT CLAUSE.

There are two fuel adjustment clause issues in this case. The first arises from CCM's longstanding and continued opposition to FACs in general. CCM's opposition is supported by nothing more than its counsel's arguments – the same arguments CCM has been making for years – and the same arguments the Commission has rejected for years. CCM's arguments have no more support today than they have had over the past several years and the Commission should continue to reject them. At bottom, Ameren Missouri has done nothing (nor has it failed to do anything) that would justify CCM's continued attempts to eliminate or otherwise weaken the effectiveness of this important regulatory mechanism.

The second FAC issue arises from MIEC's attempt to change the treatment of transmission charges in the FAC. This treatment has been in place since Ameren Missouri's FAC was first implemented just over six years ago. In summary, MIEC's attempt to change the treatment of transmission charges in the FAC now is grounded in its complete failure to recognize or acknowledge the reality of Ameren Missouri's participation in MISO's energy and ancillary services markets, the requirements of MISO's tariff and the actual operation of MISO's tariff and its markets. When those realities are acknowledged, it is clear that the transmission charges that Ameren Missouri has no choice to pay, and that have been and are properly

[322] Tr. pp. 1358-59.

recordable to Account No. 565 (transmission charges recorded in Account No. 565 always been included in the FAC), should continue to be included in the FAC.[323]

A. CCM's opposition to the FAC, and its attempts to change it, is unjustified, unsupported and should be disregarded.

Until CCM filed its position statement just before the hearings, the only contentions in this case in opposition to continuation of Ameren Missouri's FAC, or that sought to materially change it, were reflected in pleadings and testimony filed by OPC (aside from MIEC's transmission charges issue). OPC witness Lena Mantle had attempted to justify a total elimination of the FAC based on her claim that the Company had failed to comply with the FAC rule minimum filing requirements. She had also claimed that other detailed analyses should have been filed with the Company's direct case (pertaining to control, volatility/uncertainty and manageability), and claimed that this too justified a total elimination of the FAC. Finally, she sponsored what was then OPC's fallback (and completely unsupported) position to change the sharing percentage in the FAC from 95%/5% to 90%/10%.

OPC has since entered into a stipulation and agreement (the "FAC Stipulation")[324] with the Company under which OPC has changed its position such that it no longer seeks to eliminate the Company's FAC and it no longer seeks to change it in any material way. Instead, OPC's

[323] For the reasons given in Ameren Missouri witness Jaime Haro's rebuttal testimony, it is also appropriate to continue to include transportation charges associated with off-system sales in the FAC – the sales themselves and the fuel costs associated with them are in the FAC – and to also include transmission revenues in the FAC, since the charges are also included.

[324] *Non-Unanimous Stipulation and Agreement Regarding Some Fuel Adjustment Clause Issues*, between OPC and Ameren Missouri, filed March 6, 2015, which was objected to by CCM on March 7, 2015. Another stipulation and agreement that also deals with the setting of net base energy costs for the FAC was also filed on March 5, 2015, and approved on March 19, 2015 (*Non-Unanimous Stipulation and Agreement Regarding Class Kilowatt Hours, Revenues and Billing Determinants, Net Base Energy Costs and Fuel Adjustment Clause Tariff Sheets*). In terms of the FAC, the latter stipulation essentially resolves net base energy costs and FAC tariff language depending on the Commission's rulings on the transmission charges issue. The March 6, 2015 stipulation also reflects agreement on some additional FAC tariff sheet changes not dependent on the transmission charges issue.

concerns were resolved based on two basic agreements reflected in the FAC Stipulation, as follows:

- To "meet at a mutually agreeable time and location no later than May 30, 2015 in order to discuss OPC's requests that the Company provide additional description of all of the Company's accounts,[325] subaccounts and activity codes[326] used in the Company's monthly FAC reports beyond the descriptions currently included in each of the Company's monthly FAC reports, it being the intent of the Signatories to reasonably and in good faith work to agree upon additional descriptions of the costs and revenues that are included in the FAC, by account, subaccount and activity code. The Company will file the agreed-upon account, subaccount and activity code descriptions in this docket by August 1, 2015."; and

- To make a few changes to the FAC tariff sheets, most notably to change the current process for adding new RTO charges or revenues that are in the nature of existing charges or revenues included in the FAC from a process whereby the Company provides notice, with the right of others to object, to a process whereby the Company makes a filing, also with other parties having the right to object. As before, the Company would bear the burden if an objection is made and if the Commission disagreed with the addition sums would be refunded, with interest. In addition, the revised tariff sheet provision provides a similar mechanism for others to suggest the addition of a charge or revenue by making a filing with the Commission.[327]

CCM's Position Statement recommends that the Commission discontinue Ameren Missouri's FAC. CCM claims the FAC is not needed and has contributed to "excessive earnings." The evidence in this case is contrary.

As discussed in some detail in connection with the briefing of the various amortization issues above, it is simply not true that the Company's earnings have been "excessive." CCM's argument in this regard is nothing more than a re-hash of the arguments it made in the Noranda "over-earnings" complaint filed last year (File No. EC-2014-0223), which the Commission

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[325] References to "accounts" are to the Uniform System of Accounts for Electric Utilities issued by the Federal Energy Regulatory Commission. The Company does not establish accounts, but does establish subaccounts and activity codes when it believes it is warranted.
[326] The Company uses the terms "subaccounts" and "minor accounts" synonymously. The Company may from time-to-time change, add, or eliminate a subaccount or activity code. Additions, changes or eliminations will be reflected in revised Appendices to the Company's monthly FAC reports.
[327] The agreed-upon FAC tariff sheet changes are provided in an exhibit to the FAC Stipulation.

rejected. As discussed earlier in connection with briefing of the amortization issues in this case,[328] during the five completed calendar years when the Company has had a FAC, the Company has earned below the targeted ROE in three of those five years, with one of the five (2013) only being above it by 53 basis points. In the other (2012), the Company completed a rate case where the Commission concluded it needed a substantial rate increase, demonstrating that CCM's arguments about "excessing earnings" are misleading because they rely upon raw, per-book surveillance results which completely fail to account for weather or other unusual and/or one-time events that must be accounted for when judging the fairness of the Company's earnings and the justness and reasonableness of its rates. Also consider that when the FAC was approved, the net fuel costs[329] used as the base in the FAC were approximately $283.3 million.[330] Net base energy costs have increased each case since then, and in this case they stand at approximately $660 million as compared to about $581 million as of the Company's last rate case.[331] Given the foregoing facts, it is easy to see that had the FAC not been in place, the Company would not have had a reasonable opportunity to earn a fair ROE.[332]

CCM's other position on the FAC is that the sharing percentage should be changed from 95%/5% to 90%/10%. No justification is offered for this change, save CCM's continuing claim that more skin in the game on the Company's part is needed for the Company to have the right incentive to manage its net energy costs. But what is the evidence?

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[328] The Company will not re-cite portions of the record underlying these points here.

[329] This term has since been changed to "net energy costs" in the FAC tariffs.

[330] *Report and Order,* File No. ER-2008-0318, p. 62. The Commission specifically noted the continued rise in net fuel costs in its *Report and Orders* in Case Nos. ER-2010-0036, ER-2010-0028 and ER-2012-0166.

[331] *See* March 5, 2015 stipulation resolving net base energy costs and the Commission's *Report and Order* in File No. ER-2012-0166. The exact number could vary some depending on the Commission's resolution of the Noranda load and transmission charges issues, but will, in all cases, be fairly close to the $660 million.

[332] As the Commission recognized in its Report and Orders in the past several rate cases, falling power prices and the resulting fall in off-system sales has been a significant contributor to rising net energy costs. The FAC has mitigated the impact of those falling off-system sales on the Company, but if power prices rise, as they almost certainly will at some point, customers will get 95% of the benefit because of the FAC.

The Commission just approved the fourth prudence review of the Company's FAC, meaning that the operation of the FAC has been reviewed from its inception on March 1, 2009 through May of 2014.[333] There has not been a single allegation in any of those prudence reviews that the Company has failed to properly manage its net energy costs or has otherwise been imprudent regarding the factors that impact its net energy costs.[334] Seventeen adjustments to the Company's FAC have been made without controversy. Four rate cases have been completed, with similar arguments being rejected each time as the Commission has repeatedly concluded that the 5% sharing in the current FAC is appropriate. There are no new facts in this case that suggest the Commission has gotten it wrong in the past.

The Company has repeatedly acknowledged – and did so again in this case – that having a FAC is a privilege that it takes very seriously.[335] Even witnesses like Ms. Mantle, who have at times opposed the FAC or advocated for greater sharing on the Company's part, acknowledge that the fact that the Commission has discretion regarding continuing the FAC and regarding sharing are powerful incentives for the Company to properly manage its net energy costs.[336]

Like its arguments about eliminating the FAC, CCM's arguments about changing the sharing percentage are not supported by evidence that actually suggests that a change should be

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[333] *See* Staff's prudence review reports in File Nos. EO-2010-0255, EO-2012-0074, EO-2013-0407 and EO-2015-0060.

[334] The only controversy of any kind arose in File No. EO-2010-0255 because of the AEP and Wabash contracts entered into in 2009 after the ice storm that curtailed Noranda's smelter for about 14 months. Parties previously tried to argue that this showed some lack of incentive for the Company to properly manage its net energy costs with a FAC, and the Commission soundly rejected such a claim, stating: "The Commission did find that Ameren Missouri acted imprudently in that prudence review. However, the imprudence that the Commission found was related to Ameren Missouri's failure to flow revenue received from certain contracts through the fuel adjustment clause. Ameren Missouri had entered into those contracts in an attempt to replace a portion of the revenue it lost when production and the use of electricity was reduced at the Noranda aluminum smelter because of a January 2009 ice storm. Despite disagreeing with Ameren Missouri regarding the proper interpretation of a provision of the fuel adjustment clause tariff, the Commission did not find that Ameren Missouri had acted imprudently in deciding to enter into those replacement contracts. *In short, the Commission's decision in EO-2010- 0255 does not support the argument that Ameren Missouri needs a larger financial incentive within the fuel adjustment clause"* (emphasis added). *Report and Order*, File No. ER-2011-0028, pp. 82-83.

[335] Ex. 3, p. 16, l. 12 to p. 17, l. 2; p. 48, l. 12 to p. 49, l. 2.

[336] *Id.*, p. 50, l. 3- 30 (quoting Ms. Mantle's testimony).

made, but instead reflect nothing more than philosophical opposition to the FAC in its entirety, and certainly a philosophical view that utilities simply ought to be more exposed to the volatile and uncertain costs and revenues that are tracked in the FAC. However, only 18% of utilities with FACs have sharing *at all*, and even less than that have sharing when the FAC adjustments are based on historical costs, as they are in Missouri.[337] Moreover, the Commission concluded in the Company's last rate case that the Company's absorption of $30 million of "*prudently-incurred*" net energy cost increases that it will "never be able to recover" because of the 5% sharing was not *de minimis*; in fact, that number has grown to $38 million in this case, and if the 90/10% sharing CCM now supports had been in place, the number would have been $76 million.[338]

As Ameren Missouri witness Gary Rygh testified, elimination of, or changes to, the FAC in the face of the complete lack of justification for elimination or changes would be of great concern to those who are critical to the Company's access to the huge sums of capital it needs to continue investments in its system, and to the Company's ability to acquire that capital at a reasonable cost.[339]

Staff's, the Company's and even OPC's positions in this case are that the FAC should continue, and that it should not be materially changed, save the few tariff changes that have been agreed upon. The competent and substantial evidence of record in this case overwhelmingly supports those positions. CCM's opposition to the FAC, or its call to change it, should be rejected.

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[337] *Id.*, p. 52, l. 7-21. When projected costs are used, the impact of the sharing is less, meaning the impact of a 5% sharing mechanism in Missouri is greater than the impact of a 5% sharing mechanism would be in a jurisdiction where projected costs are used. *Id.*
[338] *Id.*, p. 46, l. 1-18.
[339] Ex. 42 (Rygh Rebuttal).

B. Transmission charges should continue to be tracked in the FAC, as they have been since its inception.

i. Background.

Because of the power consumed by its customers,[340] Ameren Missouri incurs transmission charges, mostly from MISO. The transmission charges are from MISO because Ameren Missouri is a MISO member, its customers' load is located within MISO's footprint and its transmission system is under MISO's functional control. This means that transmission charges arising from the combined transmission system under MISO's functional control no longer arise from each individual transmission owner's own FERC-approved tariffs, but rather, arise from MISO's Open Access Transmission, Energy and Operating Reserves Market Tariff ("MISO's Tariff").[341]

All MISO transmission charges have been included in the FAC since its inception. Although some – Ms. Mantle for the Staff and Mr. Dauphinais for MIEC – have claimed that they did not understand this (their implication being that the Company somehow acted improperly), the Commission very directly stated in its *Report and Order* in the Company's last rate case that it was appropriate for the Company to have included all of the MISO transmission charges in its FAC.[342] The Commission also determined that it was appropriate to continue including the transmission charges in the FAC, because of the Company's lack of control and because of their size and volatility. "Those costs meet the Commission's past standards for

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[340] Ex. 14, p. 18, l. 11-17 (Haro Rebuttal); Tr. p. 2057, l. 22 to p. 2058, l. 3.
[341] Addressed in Mr. Haro's Rebuttal Testimony, Ex. 14, starting at page 21.
[342] *Report and Order*, File No. ER-2012-0166, pp. 84-85 ("Under the Federal Energy Regulatory Commission's Uniform System of Accounts, transmission charges for the transmission of the utility's electricity over transmission facilities owned by others are to be recorded in account 565. Since the tariff specifically provides that costs of purchased power reflected in account 565 are to be flowed through the fuel adjustment clause, Ameren Missouri acted appropriately in doing so. Indeed, Staff agreed that account 565 costs were to be passed through the fuel adjustment clause within the current language of the tariff and no party has alleged that Ameren Missouri should be required to make any adjustment for transmission charges that have already been passed through the fuel adjustment clause" (footnotes omitted)).

inclusion in the fuel adjustment clause in that they are significant in amount, volatile in that they are not only rapidly rising, but are also uncertain in amount, and they are largely beyond the control of Ameren Missouri. The Commission finds that MISO transmission costs should continue to be flowed through Ameren Missouri's fuel adjustment clause."[343] Nothing has changed since the Company's last rate case that rebuts the Commission's just-quoted conclusions.

While perhaps unspoken, it is quite clear that the rise (and expected continued rise) in MISO Schedule 26A transmission charges has gotten MIEC's attention and that, because of that rise, MIEC wants to avoid bearing the increases in those Schedule 26A charges (above the level of such charges included in base rates) that is expected to occur over the next several years. This is because with the Schedule 26A charges continuing to be reflected in the FAC, 95% of the increases will be reflected in FAC adjustments.

MIEC's attempt to avoid those increases in this case is a continuation of its failed attempt to avoid those increases in the Company's last rate case. In that case, MIEC took a run at avoiding the increases on several fronts, including based on the testimony of MIEC witness James Dauphinais.

MIEC's first argument was based on Mr. Dauphinais' claim under the then-language of the FAC tariff that an exclusion in the tariff for "capacity charges under contracts of greater than one year" applied to most of the MISO transmission charges, including those arising under Schedule 26A, meaning that by the FAC tariff's terms the transmission charges were excluded. The Commission rejected Mr. Dauphinais' argument. MIEC was not done, however.

MIEC also claimed that the transmission charges at issue were not "transportation" charges, as the term transportation is used in the FAC statute (§ 386.266, RSMo.). The

[343] *Id.*, pp. 88-89 (footnotes omitted).

Commission rejected MIEC's argument, and the Court of Appeals rejected MIEC's (and its joint appellants') argument on this point as well.

MIEC also supported a Staff argument made in the Company's last rate case that was also designed to result in the exclusion of at least the Schedule 26A transmission charges from the FAC; that is, the Staff's argument was that the transmission charges violated § 393.135, RSMo. (2000) because, the Staff said, the charges were for construction of transmission lines that were not in service. The Commission, recognizing that as far as the Company was concerned, the transmission charges were simply charges for transmission (having nothing to do with the *Company's* construction of anything), and ruled that there was no violation of § 393.135. While the Court of Appeals did not directly resolve the question, its opinion made very clear that there were significant flaws in the § 393.135 argument.[344] MIEC does not make the argument here.

Finally, MIEC claimed on appeal that it had made what appears to be a variant of the argument it is making now, but the Court of Appeals determined MIEC failed to preserve it.[345] MIEC's argument: that the vast majority of the transmission charges paid by Ameren Missouri are not associated with transmission of "purchased power" and that therefore they are ineligible for inclusion in the FAC.[346] MIEC argues that Ameren Missouri "self-supplies" most of the power its customers consume from its own generating units (MIEC sometimes uses the term "self-generates") and that therefore it does not purchase it. Although Mr. Dauphinais makes no attempt whatsoever (despite having the last word) to rebut the overwhelming evidence that

[344] MIEC's support for the Staff's specific argument in this regard became clearer in MIEC's joint appeal with OPC and CCM of the Commission's *Report and Order* in File No. ER-2012-0166, where it and the other appellants directly made the Staff's § 393.135 argument. While the Court of Appeals indicated it did not have to resolve this argument to resolve the appeal, it nevertheless rejected it e*x gratia*. ***In the Matter of Union Elect. Co, Office of Public Counsel, AARP, Missouri Industrial Energy Consumers, and Consumers Council of Missouri v. Pub. Serv. Comm'n***, 422 S.W.3d 358, 368 (Mo. App. W.D. 2103).
[345] *Id.* at 364-65.
[346] At bottom, this is really a legal argument – what does "purchased power" mean in the FAC statute.

indeed Ameren Missouri does in fact buy all of the power its customers consume from the MISO market, he nevertheless contends that Ameren Missouri witness Jaime Haro's statement that in fact Ameren Missouri does buy (purchase) all such power is "absurd." Neither the facts, nor the law, support Mr. Dauphinais' and MIEC's theory.

ii. The transmission charges at issue are associated with purchased power.

Let's start with the facts. As a function of the operation of the MISO market, whose mechanics are provided for in its Tariff, Ameren Missouri sells all of the megawatt-hours ("MWh") it produces to the MISO market and it *separately* buys from the MISO market – at a different price and location – all of the MWhs its customers consume. How do we know this? Because the MISO's tariff and Business Practices Manuals ("BPMs") (which are referred to in MISO's tariff) tell us that this is the case.[347] The settlement statements the Company receives from MISO illustrate this as well. So too does testimony given by Mr. Dauphinais in other cases, including in File No. EC-2014-0224.

In that case, Mr. Dauphinais testified that *"As a participant in the MISO Regional Transmission Organization ('RTO'), Ameren Missouri must clear all of its generation and all of its load in the MISO market."* He went on to state *"the reduction in Ameren Missouri's ANEC can be reasonably and conservatively estimated as the cost avoided by Ameren Missouri by not having to clear the Noranda retail sales in its MISO market and transmission settlements for its load."* (ANEC is Actual Net Energy Cost).[348] As discussed below, to "clear" generation and to "clear" load means to *sell* and *buy* MWhs.

[347] Incidentally, the MISO tariff does reflect the fact that Ameren Missouri purchases all of the power its customers consume, and the MISO tariff, like a tariff in Missouri, also has the force and effect of law. ***Central Iowa Power Coop. v. MISO***, 561 F.3d 904, 913 (8th Cir. 2009).
[348] Ex. 14, p. 23, l. 8-13.

Mr. Dauphinais also testified about "net" off-system energy sales and "net" power purchases, but as Mr. Haro pointed out, there can never be a reduction in gross purchased power (i.e., no netting) if the power was never purchased in the first place.[349]

The MISO's Tariff and BPMs make crystal clear that *all* of the energy consumed by Ameren Missouri's customers is purchased by Ameren Missouri as a function of the operation of the MISO market. The tariff and BPMs are replete with references to "purchases" of energy."[350] These documents do not speak in terms of "net purchases." The energy is simply purchased. The Tariff and BPMs also create a construct where the Company bids the MWhs (again, not a net number) it expects its customers to consume the next day. In simple terms, the Company is placing a bid to buy the gross amount of energy it is going to need at a price ultimately set by the operation of the MISO energy market.[351] Moreover, MISO *charges* Ameren Missouri for the *gross* MWhs it purchases, as shown by the settlement statements it receives from MISO, as discussed by Mr. Haro at page 27 of his Rebuttal Testimony.[352] Aside from calling Mr. Haro's argument "absurd" and otherwise positing a few other points, Mr. Dauphinais rebutted none of the provisions of the MISO's tariff or BPMs in his Surrebuttal Testimony.

Instead, MIEC relies upon the fact that Ameren Missouri's accounting nets the dollars it is due for the MWhs it sells to the MISO market against the dollars it owes for the MWHs it purchases from the MISO market to argue that the netting proves that Ameren Missouri only purchases the net MWhs. From that base position, MIEC then says that the difference between the gross and the net is "self-supplied," and that "self-supplied" power is not "purchased power"

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[349] *Id.*, pp. 23-24 and, in particular, p. 24, l. 14-15.
[350] *Id.*, p. 24, l. 21; p. 25, l. 19-20, 26; Schedule JH-R1 (definitions of "Day Ahead Energy and Operating Reserve Market" and "Fixed Demand Bid" and "Real-Time Energy Purchases" and "Real-Time Energy and Operating Reserve Market").
[351] Mr. Haro's rebuttal testimony, pages 24-26 and Schedule JH-R1 discuss these bids in more detail.
[352] *See also* Schedule JH-R2.

under the FAC statute. MIEC prominently advanced this point by asking Mr. Haro only a few questions on cross-examination, all of which pointed to the accounting for the net dollars in the Company's surveillance reports, and by also having Mr. Dauphinais discuss the accounting in his surrebuttal testimony. But the rest of the story demonstrates that MIEC's position is completely at odds with the reality of the operation of the MISO market, as governed by its Tariff.

First, Ameren Missouri does not "self-supply" anything.[353] As Mr. Haro explained to Chairman Kenney in response to his questions, "self-supply" is not even defined in the MISO Tariff.[354] Moreover, when self-supply does come into play, it relates to resource adequacy (i.e., capacity, not energy) or to station service (the energy consumed by the generation plant itself).[355]

Second, while Ameren Missouri does self-*schedule* certain generating plants on a limited basis as discussed further below, self-scheduling does not mean that Ameren Missouri somehow "bypasses" the MISO market and then sells the MWhs its generators produce directly to its customers. To the contrary, even when units are self-scheduled, the MWhs those units generate in fact are sold to the MISO market.

Third, the MWhs sold to the MISO market – which are all that are generated – are sold at different locations and prices than are the purchases Ameren Missouri makes to resell to its customers.[356]

Fourth, "self-supply" as MIEC attempts to use the term has nothing to do with self-scheduling. As noted, Ameren Missouri does self-schedule its hydroelectric units (like the Osage Energy Center) and it does so to optimize the generation (which benefits customers), as explained by Mr. Haro during the evidentiary hearings, as summarized in the next few

353 Tr. p. 2058, l. 4-8.
354 Tr. p. 2039, l. 10 to p. 2040, l. 4.
355 Tr. p. 2042, l. 5 to p. 2044, l. 9.
356 Tr. p. 2045, l. 5-9.

sentences.[357] Ameren Missouri offers its generation into the MISO day-ahead market and for the reasons noted below, it self-schedules the hours it wants Osage to run at a set volume.[358] This is because a plant like Osage can't run 24-hours per day because it will not have enough water each day to do so. However, since water is "free," and the MISO real time market does not optimize over the entire day as the day-ahead market does, absent self-scheduling which hours the hydro plant will run, it would be dispatched in real-time by MISO to run starting in the first hour of the day (again, because that water used for generation is free), when power prices may not be (probably are not) optimal. This would result in quickly exhausting the available water for generation and leaving the unit unable to meet its day-ahead award. Consequently, to minimize the negative effects of deviating from its day-ahead award, Ameren Missouri schedules the MWhs in the day that Osage should run to coincide with its day-ahead award. Put succinctly, self-scheduling has nothing to do with whether Ameren Missouri sells the MWhs it produces or buys the MWhs its customers consume, (and certainly has nothing to do with tying specific generation output to load), but rather, is "just a parameter on how long a generator can run."[359]

Finally, that Ameren Missouri nets the accounting for the amounts received for the MWhs it sells with the amounts it is charged for the MWhs it buys is completely irrelevant to whether the total (gross) MWhs are being sold or purchased. As Mr. Haro testified, the FERC requires that Ameren Missouri report on a net dollar basis.[360] But FERC also clearly recognizes

[357] *See* Tr. p. 2039, l. 10 to p. 2044, l. 9; p. 2059, l. 6 to p. 2061, l. 4.
[358] For Callaway or a baseload plant the plant can run 24 hours per day and its dispatch above its minimum load (set for operational reasons) will depend on the economics of running at various levels in each hour of the day.
[359] Tr. p. 2060, l. 24 to p. 2061, l. 4. Although he tried, Mr. Dauphinais' testimony indicates that he does not disagree with Mr. Haro's description of what self-schedule is, and he concedes that "self-supply" is not defined in the MISO tariff at all. Tr. p. 2085, l. 2-15.
[360] Tr. p. 2061, l. 13-22.

that the *gross* MWhs of energy that are consumed by an RTO participant's customers are purchased from the RTO, as evidenced by FERC Order 668[361] and its follow-up Order 668-A.[362]

Even Mr. Dauphinais was forced to admit that this was true. Mr. Dauphinais agrees that Ameren Missouri is a market participant in MISO's energy markets and that it participates in the MISO's energy markets "on behalf of its customers."[363] He agrees that when he uses the terms "cleared load" and "cleared generation" that means that there is a gross amount of generation (MWhs) from the market participant's generation in a given hour, and there is a gross amount of load (MWhs) taken by the market participant's load in a given hour.[364] He agrees that when the FERC refers to "total cleared load," it is referring to "gross purchases."[365] And he agrees that the gross MWhs generated and gross MWhs taken are netted for reporting purposes.[366] Moreover, he agrees that the FERC requires that utilities that use RTO markets to serve their customers (like Ameren Missouri) must maintain detailed records of their *gross* sales and of their *gross* purchases.[367] To use the language of Order 668, public utilities must "maintain detailed records for auditing purposes of the *gross* sale and purchase transactions *that support the net energy market amounts* recorded on their books" (emphasis added).[368]

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[361] Ex. 66. The entire paragraph from Order 668 from which Mr. Dauphinais plucked just a single sentence in his Surrebuttal Testimony is as follows: "80. Recording RTO energy market transactions on a net basis is appropriate as purchase and sale transactions taking place in the same reporting period to serve native load are done in contemplation of each other and should be combined. *Netting accurately reflects what participants would be recording on their books and records in the absence of the use of an RTO market to serve their native load.* Recording these transactions on a gross basis, in contrast, would give an inaccurate picture of a participant's size and revenue producing potential. The Commission will, therefore, adopt the proposed accounting for RTO energy market transactions with certain modifications and clarifications as discussed below. *The Commission does expect public utilities, however, to maintain detailed records for auditing purposes of the gross sale and purchase transactions that support the net energy market amounts recorded on their books" (emphasis added).*
[362] Ex. 67.
[363] Tr. p. 2073, l. 4-6; p. 2074, l. 2-6.
[364] Tr. p. 2073, l. 7-15.
[365] Tr. p. 2076, l. 15-22.
[366] *Id.*
[367] Tr. p. 2075, l. 1-25; p. 2076, l. 1-14.
[368] Ex. 66.

The foregoing leads to the inescapable fact (no matter how many times Mr. Dauphinais calls it "absurd" or otherwise denies the realities of Ameren Missouri's MISO participation) that Ameren Missouri does indeed purchase all of the MWhs it then resells to its customers. It has to, for if there were no gross purchases there would be nothing to net. One does not net "against net" to arrive at "net." To the contrary, one nets the gross of one thing (sales) against the gross of another thing (purchases) and when the netting is done the result is a net sum. Put another way, if Ameren Missouri only purchases the MWhs that equate to the net dollars that it reports as purchased power costs, then the net and the gross would be the same.[369] And if they are the same, there is nothing to net.

The bottom line is that Order 668 embodies *exactly* what Mr. Haro testified to, and it embodies exactly what Ameren Missouri has told the Commission: that as a function of the operation of the MISO Tariff governing market operations, Ameren Missouri indeed purchases all of the MWhs it then sells to its customers. On the one side we have the FERC agreeing with Ameren Missouri, we have the MISO's Tariff agreeing with Ameren Missouri, we have the MISO BPMs agreeing with Ameren Missouri and we have MISO settlement statements that show quantities of gross sales and quantities of gross purchases. On the other, we have Mr. Dauphinais calling Mr. Haro's position – which is based upon the FERC and on MISO and on how the markets actually work – "absurd" based on nothing more than Mr. Dauphinais' personal opinion that "purchased power" is limited to MWhs that equate to the net purchased power dollars reported in accounting records that the Company is required by FERC to keep that way.

MIEC doesn't want the increases in Schedule 26A charges to be included in the FAC. It doesn't like deferral mechanisms; it likes riders like a FAC even less. It has always supported

[369] Keep in mind, for example, that the surveillance reports Mr. Haro was shown during the evidentiary hearings and which MIEC placed in evidence are simply reporting net dollars. Ameren Missouri isn't buying or selling dollars. It is buying and selling energy – MWhs – and it buys and sells the gross.

the benefits MISO participation brings to Ameren Missouri and its customers, but it would rather avoid increases in this particular burden. It has now pursued at least four distinct lines of attack on inclusion of these transmission charges in the FAC. Its latest attack is no more valid than the other three. The FAC tariff should remain as-is with respect to the treatment of transmission charges.

C. Commissioner Hall's FAC-related question.

Near the end of the evidentiary hearing, Commissioner Hall posed the following question regarding the "N" factor:[370]

> ***What would be the effect on Ameren [Missouri] 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 effect of eliminating the N factor will be to create an extraordinary business risk for Ameren Missouri. As has been discussed in numerous proceedings at the Commission, Noranda consumes more than 10% of the power Ameren Missouri sells its customers every year. Ameren Missouri does not even control the transmission lines that Noranda uses (under separate arrangement with Associated Electric Power Cooperative, Inc.) to obtain power from Ameren Missouri. Although it was no one's fault, those power lines were downed by a severe ice storm in 2009, leading to huge potential financial losses for Ameren Missouri, which ended-up spawning significant disagreements in two prudence reviews, a court appeal, a contested AAO proceeding and now a contest about that AAO in this case.[371] The N factor was implemented as

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[370] As noted during the hearings, the FAC tariff no longer literally includes an "N" factor, but what used to be labelled as such in the FAC tariff and is now referred to as a 12(M) adjustment is materially the same as the "N" factor originally included in File No. ER-2010-0036. When originally implemented, "N" stood for "Noranda," since Noranda is the only customer in the 12(M) rate class. We will sometimes refer to the 12(M) adjustment as the N factor herein.

[371] And because of the particular nature of the disputes that have occurred, including regarding the AAO and the order granting it, the Company has in fact suffered a significant financial loss because of the ice storm insofar as its earnings have already been reduced by the margins it lost. A significant part of that loss would be mitigated if the

a result of a stipulation reached in File No. ER-2010-0026 and, to obtain agreement on it, as is the nature of all compromises, the Company gave some things up. The N factor has not had to operate in the approximately four years since it was implemented – and all parties undoubtedly are glad about that – but the need for it could arise again.

The N Factor is fair. Ameren Missouri has to suffer a material reduction in Noranda load before it is triggered, and then can only keep margins from revenues tracked in the FAC because of such a reduction that keep it whole (no more), assuming that prices realized for power are at or above the retail rate that was being paid by Noranda. To the extent they are not Ameren Missouri is not kept whole, but at least the loss of Noranda load is mitigated.

There is no reason to eliminate the N factor (i.e., doing so would be inappropriate). Indeed, there is no evidence in this case that provides any justification to eliminate it. In fact, the record supports keeping it. Both stipulations which touch on FAC issues reflect the signatories' agreement on specific changes that would be made to the FAC tariff, depending on the Commission's resolution of remaining contested issues (essentially, regarding the level of Noranda load to be used to set rates and regarding transmission charges), with no suggestion that the N factor should be eliminated. The first stipulation that preserved disputes about Noranda's load and transmission charges in fact is considered unanimous, and was approved by the Commission. And in the second stipulation, OPC, which initially recommended elimination of the N factor, has changed its position and no longer makes such a recommendation.

VIII. LABADIE ESPS

In late 2014, Ameren Missouri placed in service electrostatic precipitators ("ESPs") on Labadie Energy Center Units 1 and 2. The ESPs were installed to bring those units into

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Commission does reflect an amortization of the sums deferred under the Noranda AAO in this and future cases until the amortization is complete.

compliance with federal Mercury and Air Toxics Standards ("MATS"), which apply to existing power plants.[372] Ameren Missouri commenced its MATS-compliance efforts several years ago, and the Company's compliance plans initially called for staged installation of ESPs on all four units at Labadie.[373] Although ESPs will be installed on Labadie Unit 4 by early 2016, emissions improvements achieved through installation of ESPs on Units 1 and 2 will allow Ameren Missouri to defer installation of ESPs on Labadie Unit 3.[374] That deferral will result in savings for both the Company and its customers.

Before Ameren Missouri can add its investment in the ESPs to rate base, the Commission must first determine two things: whether the investment is prudent, and whether the investment is used and useful in providing service to customers. With the exception of costs associated with damaged collector plates – an issue resolved as part of a broader stipulation the Commission approved by its order dated March 19, 2015 – no party other than Sierra Club contends Ameren Missouri's investment in the ESPs is imprudent. And because they satisfied all of the in-service criteria agreed-upon between the Company and the Staff prior, no party (Sierra Club included) argues the ESPs are not fully used and useful. So insofar as questions relevant to this rate case are concerned, all competent and substantial record evidence supports including the Company's investment in the ESPs in rate base.

The sole contested issue concerns Sierra Club's contention that Ameren Missouri's decision to install the ESPs was imprudent. Sierra Club claims that to demonstrate the prudence of its investment, the Company must present evidence establishing the long-term viability of Labadie. However, Sierra Club's contention is flawed for at least two reasons.

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[372] Ex. 28, p. 8, l. 6-10 (Moehn Direct).
[373] Ex. 900, Sch. EDH-3 (Hausman Direct).
[374] Ex. 26, p. 18, l. 1-4 (Michels Amended Rebuttal).

First, Sierra Club's concerns about Labadie are based on carbon dioxide emissions rules that do not yet exist. The Environmental Protection Agency ("EPA") has announced rules designed to implement greenhouse gas limitations imposed by the federally-mandated Clean Power Plan that will not be issued in final form until sometime this summer.[375] Because those rules won't be final until weeks or months after the operation of law date in this rate case, it would be impossible to consider their impact on Labadie even if the Commission were inclined to do so. More importantly, the Commission's decision regarding the ESPs cannot be based on, or influenced by, Sierra Club's speculation about what the EPA's final rules will include. Such rank speculation is not competent and substantial evidence, so it cannot provide a basis for the Commission's decision in this case.

Even though concerns raised by Sierra Club regarding Labadie's long-term viability are not relevant to this case, Ameren Missouri witness Matt Michels addressed those concerns in his rebuttal testimony. As summarized by Mr. Michels, the analysis the Company included in its IRP filing fully supports continued operation of Labadie, including investments in additional pollution controls:

- Ameren Missouri has sufficiently evaluated the potential impacts of the EPA's proposed regulation of carbon dioxide emissions – Ameren Missouri has included in its recent IRP filing an analysis of the potential impact of compliance with the EPA's proposed CPP [Clean Power Plan] on Ameren Missouri's preferred resource plan. That analysis reflects compliance with the requirements of the proposed rule with continued operation of all four Labadie units throughout the 20-year planning horizon evaluated in the IRP (i.e., through 2034).

- Ameren Missouri has appropriately accounted for regulation of carbon dioxide emissions in its IRP analysis – Ameren Missouri performed its IRP analysis under a range of scenarios for future regulation of carbon dioxide emissions. Some scenarios reflect implementation of an explicit price on carbon dioxide emissions, but most reflect implementation of regulations that alter the mix of resources in the electric energy market, including varying

[375] Ex. 26, p. 17, 10-12.

levels of retirements of coal-fired generators, without implementation of an explicit price on carbon dioxide emissions. This is the very kind of "indirect cost" regulation of carbon dioxide emissions to which Dr. Hausman refers in his direct testimony.

- Ameren Missouri's analysis of retirement of Labadie supports its continued operation with investments in pollution controls – Ameren Missouri's analysis of the retirement of Labadie accounts for the potential to avoid the vast majority of expected environmental compliance costs for the plant and shows that continued operation of the plant, including all costs of environmental compliance, *saves customers over $3 billion*.[376]

During the evidentiary hearing, Mr. Michels further established that Ameren Missouri supports its assumptions about Labadie's continued viability in part based on a comparison of Labadie's production costs compared to those of other coal-fired generating facilities operating in the United States. Exhibit 65HC displays the results of the most recent version of that comparison, and shows Labadie is among the lowest-cost coal generating facilities in the country. Mr. Michels also testified that under *whatever* carbon dioxide emissions standards the EPA ultimately approves, high cost, coal-fired generators will close first, and closing those plants likely will satisfy all anticipated carbon dioxide requirements. That means over the remainder of its useful life, carbon dioxide regulations likely will not significantly affect a low-cost plant like Labadie, Sierra Club's suggestions to the contrary notwithstanding.[377]

Although questions regarding the long term viability of Labadie are not germane to this rate case, even if they were, the Company's evidence shows the concerns expressed by Sierra Club are overblown and unwarranted. As noted previously, the only issues relevant to this rate case are whether Ameren Missouri's investment in the ESPs is prudent, and whether the ESPs are used and useful. Because there is *no* evidence supporting a negative finding on either of

[376] Ex. 26, p. 4, l. 10 to p. 5, l. 11.
[377] Tr. p. 1951, l. 14 to p. 1952, l. 24.

those issues, the Commission should include in the rate base used to set rates in this case the full value of the Company's investment in the Labadie ESPs.

Second, Sierra Club's "evidence" is so weak and speculative that it completely fails to create a serious doubt about the prudence of the Company's investment in the ESPs. Consequently, Ameren Missouri is entitled to the presumption of prudence afforded it by law, meaning that as a matter of law there is absolutely no basis on the record in this case for the Commission to exclude the ESP investments in rate base. *See, e.g.,* ***State ex rel. Nixon v. PSC***, 274 S.W.3d 569, 581 (Mo. W.D. App. 2009) ("In evaluating the prudence of a utility's action, the utility enjoys a presumption that it acted prudently until a party presents evidence that raises a serious doubt with the expenditure. ***Associated Natural Gas Company v. Pub. Serv. Comm'n,*** 954 S.W.2d 520, 528 (Mo. App. W.D. 1997)"). The bottom line is that the Sierra Club has completely failed to meet *its* burden to create a serious doubt about the prudence of Ameren Missouri's decision to install ESPs on two of the four Labadie units, a plant with some of the lowest production costs in the country, so that the plant can continue to produce electricity and provide capacity for the Company's system.

IX. TWO-WAY STORM RESTORATION COSTS TRACKER AND BASE LEVEL OF STORM COSTS

In Ameren Missouri's last rate case, the Commission approved a two-way tracker to facilitate the full reflection in the Company's rates of prudently-incurred non-internal labor O&M storm restoration costs. As the Commission noted in its *Report and Order* from that case, although traditional regulatory mechanisms for reflecting costs incurred to restore service following major storms have worked relatively well, major storm costs are particularly well suited for a two-way tracker.

The Commission reached its conclusion for at least three reasons. First, the Commission acknowledged Ameren Missouri has no control over when major storms occur and very little ability to control restoration costs following such events.[378] Second, the Commission recognized Ameren Missouri has a long and consistent record of spending money prudently when restoring service following major storms in its service area.[379] Finally, the Commission found that under traditional modes of regulation, major storm restoration costs can have a significant impact on the Company's ability to earn a reasonable return, but a tracker mechanism can significantly mitigate that impact.[380] These considerations allowed the Commission to overcome its general skepticism regarding trackers and adopt a two-way tracker for major storm restoration costs.

The need to quickly restore service following a major storm and Ameren Missouri's commitment to do so are beyond question. As David Wakeman, the person who oversees storm restoration efforts, explained:

> Major storm restoration is an extremely important part of our business, and prompt restoration of service is critical to customers and the communities we serve. Our customers, including business owners and community leaders, as well as the Commission, expect we will react to these events promptly and professionally, and that our response will safely and efficiently restore service as quickly as possible. These expectations are not mitigated if a faster response requires the expenditure of significantly more funds than would be necessary if we were less aggressive in responding to storm damage. We take this responsibility very seriously, and I believe our customers understand the value of our prompt response and the associated costs.[381]

There also is no question the Company must expend substantial amounts of capital and other resources and incur significant costs to restore service following a major storm. Exhibit 58 graphically illustrates this point.[382] The storm described in Staff's report, which "resulted in the

[378] *Report and Order*, File No. ER-2012-0166, p. 96.
[379] *Id*.
[380] *Id*., pp. 96-97.
[381] Ex. 46, p. 5, l. 1-9 (Wakeman Rebuttal).
[382] Ex. 58.

most significant damage to the UE distribution system in history," caused more than 36,000 of Ameren Missouri's customers to lose electric service for some period. Freezing rain accumulating on aerial lines caused more than 3,600 poles to break due to heavy ice loading, which resulted in severe damage to most of the Company's sub-transmission and distribution circuits serving Southeast Missouri. And although Ameren Missouri restored service to all its customers within a few days – far sooner than other utilities in the area – Staff's report documents the all-out effort required to achieve that result. The following data from the "Storm Restoration Summary" included in Staff's report shows the scope of that effort:

PERSONNEL	**MATERIALS**	**LOGISTICS**
• 2,400 linemen • 555 tree trimmers • 161 field checkers • Several hundred stores and logistical support personnel and supervisors	• 6,973 cross arms • 3,771 poles • 659 transformers • 1.5 million feet of wire and cable	• 15,500 hotel rooms • 2,300 other sleeping arrangements • 76,000 meals • 1,250 loads of laundry • 44 buses

These data also provide insight into the types of capital expenditures the Company must make and the costs it incurs to restore service following a major storm.

In its *Report and Order* approving the current tracker, the Commission found "[m]ajor storm restoration costs are particularly well suited for inclusion in a two-way tracker."[383] The Commission further explained the tracker "rationalizes" the method by which Ameren Missouri recovers prudently-incurred storm restoration costs, and does so without increasing "the burden of prudence review imposed on Staff and other parties," and also without "reducing Ameren Missouri's incentive to control costs."[384] But one of the biggest advantages of the tracker is its "two-way" feature, because as it tracks major storm restoration costs both above and below the

[383] *Report and Order*, File No. ER-2012-0166, p. 96.
[384] *Id.*, pp. 96-97.

amount set in base rates, "the tracker will return such costs to ratepayers if Ameren Missouri's service area is not hit by a major storm."[385] Like the vegetation management and infrastructure inspection trackers discussed elsewhere in this brief, the two-way feature of the tracker creates a win-win situation for both the Company and its customers.

Staff, OPC, and MIEC each oppose continuing the two-way tracker for major storm expense. Although these parties claim they oppose the tracker because they believe traditional modes of regulation adequately ensure Ameren Missouri will recover all storm restoration costs, the Company suspects their opposition is based on a dislike for deferrals generally. The tracker's opponents argue that under traditional modes of regulation, a utility is allowed to request an AAO, which would permit deferral of major storm-related costs between rate cases, and also enable the utility to amortize the regulatory asset or liability created by the deferral through rates set in subsequent rate cases.[386]

But these parties fail to recognize, or at least fail to acknowledge, that traditional modes of regulation are significantly inferior to the current tracker in most, if not all, critical respects. For example, traditional modes of regulation do not provide that Ameren Missouri will always be able to obtain the AAO necessary to defer its non-internal labor O&M storm restoration costs. And as the Commission recognized, piecemeal AAO requests are a less rational means of dealing with storm restoration costs.

In addition to the general reservations stated above, there also is considerable uncertainty as to how, or whether, a utility can satisfy the requirements Staff claims apply to a request for an AAO. Under cross-examination, Staff's witness Kofi Boateng acknowledged there are two standards the Commission traditionally employs to determine whether a utility is entitled to an

[385] *Id.*, p. 97.
[386] Ex. 205, p. 4, l. 12 to p. 5, l. 2 (Boateng Rebuttal).

AAO. First, the costs to be deferred must "pertain to an event that is extraordinary, unusual, and unique and not recurring." And second, costs associated with the event must be financially material.[387] However, when asked how Staff determines if an event is extraordinary, unusual and unique, and non-recurring, Mr. Boateng was unable to articulate a specific standard.

> **Q. How does Staff go about determining if a storm is extraordinary, unusual, and unique and not recurring?**
>
> A. I think the company has a burden of proof to apply for the AAO. And based on the circumstances, Staff will review whether it merits an AAO or not. You file an application for AAO, so when the company files for the application then we'll have a chance to review whether we have to support it.
>
> Q**. But how – what standards does the Staff use to determine whether or not the company has met its burden of proof?**
>
> A. I think based on what I just read from Mr. Oligschlager's [sic.] testimony, it has to be an extraordinary event. And so if we have consistent storm all year round, maybe from maybe – either take, for instance, if Jefferson City always have storm every – all year round and maybe another city, maybe St. Louis, doesn't have it, it's easy to predict that storm that occurs here might be – not be strong after all because you always have storms, whereas St. Louis might not have it, so in the event St. Louis have maybe a storm, that is more the normal that you can predict that that is extraordinary storm, so in this case that the criteria we use to determine whether this is extraordinary or not.[388]

Whatever standard Staff uses, Mr. Boateng agreed it would be a subjective standard, which means two or more Staff members looking at the same data could reach different conclusions about whether a storm qualifies as extraordinary.[389]

The real world problems Staff's unspecific, subjective AAO standard poses for a utility like Ameren Missouri were on clear display when Mr. Boateng was asked whether the January 2009 ice storm would satisfy the "extraordinary, unusual and unique, and not recurring" standard. Despite (1) all the information regarding the severity of the storm and Ameren

[387] Tr. p. 859, l. 10 to p. 860, l. 2. In fact, Staff has in the past advocated for a "materiality standard," but the Commission has never adopted one. Regardless, Staff often argues for such a standard.
[388] Tr. p. 861, l. 5 to p. 862, l. 7.
[389] Tr. p. 863, l. 18 to p. 864, l. 6.

Missouri's restoration efforts in Staff's own report, (2) Staff's conclusion "[t]he intensity and geographical concentration of the outages was more extensive than what the Company had experienced in the past,"[390] (3) Ameren Missouri's statement that the storm "resulted in the most significant damage to the UE system in history," and (4) the extensive list of personnel and capital the Company deployed and the significant expense it incurred to restore service, Mr. Boateng was unable to conclude the storm was extraordinary.[391] Mr. Boateng's inability – or unwillingness – to concede the 2009 ice storm satisfies the requirements for an AAO shows traditional modes of regulation are an inadequate substitute to use of a two-way storm tracker for major storm costs.

Regarding the sometimes argued requirement that costs must be material to be deferred through an AAO, Mr. Boateng testified the Commission usually uses five percent of a utility's net income as the materiality threshold.[392] According to the Staff, Storm costs that fail to meet this threshold would not be eligible for deferral, and therefore Staff would presumably oppose an AAO and ultimately amortization of the deferred sums in a later rate case.

In contrast, the tracker enables Ameren Missouri to avoid the uncertainties of traditional modes of regulation described above. Under the tracker, a storm is classified as "major" based on a completely objective standard – a mathematical formula prescribed by IEEE Standard 1366 that looks at how long customers' service is interrupted (measured in minutes).[393] The tracker also has no requirement storm costs satisfy an arbitrary materiality standard; as long as the storm qualifies as "major" under IEEE Standard 1366, all non-internal labor O&M restoration costs are included in the tracker. In addition, the tracker allows Ameren Missouri to defer costs it incurs

[390] Ex. 58, p. 3.
[391] Tr. p. 868, l. 8-21.
[392] Tr. p. 862, l. 14-21.
[393] Tr. p. 855, l. 10-14.

staging personnel and resources to respond to severe weather conditions, even if those conditions never develop into the major storms forecasters predict. Under traditional modes of regulation, such costs would not qualify for an AAO because they were not caused by an extraordinary event.

The tracker's two-way feature is perhaps its biggest advantage over the traditional modes of regulation championed by Staff, OPC, and MIEC. As described above, traditional modes of regulation make full reflection of a utility's prudently-incurred storm restoration costs in rates because obtaining an AAO and ultimate amortization of the costs in future rates is far less certain. But beyond that, traditional modes of regulation do not provide any means to reflect in customer rates storm costs below the tracker's base. But the tracker tracks costs that are both less than and greater than those included in rates, so customers benefit from lower future rates if Ameren Missouri's actual storm-related expenditures are less than expected, which happens when large storms occur less frequently. Conversely, when large storms do occur, the tracker protects the Company's interests.

None of the parties opposing the tracker claim it has not worked precisely the way the Commission intended. Instead, they oppose the tracker simply because it is not "traditional." In the aftermath of a major storm, Ameren Missouri should be able to focus all its energy on restoring service as quickly as possible, and the Company should not be distracted from those efforts by concerns about whether it will be allowed to reflect the costs it prudently incurs for restoration in its rates. Although Mr. Wakeman stated eliminating the tracker will not detract from Ameren Missouri's resolve to do everything necessary to restore service following a storm,[394] he also acknowledged that the uncertainty regarding whether the Company will be able

[394] Tr. p. 843, l. 2-12.

to reflect all its storm related costs in its rates could put pressure on management to cut costs elsewhere.[395]

In addition to issues related to the tracker, the Commission also must determine the proper amount of normalized storm costs to include in the revenue requirement used to set rates in this case. Ameren Missouri and Staff agree a 60-month normalization period should be used, which yields annualized storm costs of $4.6 million.[396] OPC proposes an eighty-four month normalization period, which yields annualized costs of $5.9 million,[397] while MIEC's normalized amount, which is based on a 72- month average, is $5.8 million.[398]

The Commission should adopt the amount proposed by the Company and Staff because 60 months represent a reasonable normalization period for storm costs. As the Commission noted in its *Report and Order* in File No. ER-2012-0166, a longer normalization period does not necessarily yield a better result, because at some point the data cease to be reliable.[399] In that case, the Commission determined 60 months was the appropriate normalization period for storm costs, and neither OPC nor MIEC has provided any evidence in the current case proving a longer period is more reliable.

X. TWO-WAY VEGETATION MANAGEMENT AND INFRASTRUCTURE INSPECTION COSTS TRACKER AND BASE LEVEL OF COSTS

In File No. ER-2008-0318, the Commission approved tracker mechanisms for costs Ameren Missouri incurs complying with rules governing standards and schedules for vegetation management and infrastructure inspection, 4 CSR 240-23.030 and 4 CSR 240-23.020,

395 *Id*.
396 Ex. 31, p. 29, l. 16-18 (Moore Rebuttal).
397 *Id.*, l. 21-22.
398 *Id.*, l. 19-20.
399 *Report and Order*, File No. ER-2012-0166, p. 99.

respectively.[400] In each of the Company's subsequent rate cases – most recently in File No. ER-2012-0166 – the Commission authorized Ameren Missouri to retain those trackers, at least until the Company completed a full cycle of prescribed vegetation management and infrastructure inspection activities.[401]

The way the two trackers operate is simple and straightforward. The Commission determines expected expense levels for vegetation management and infrastructure inspection activities and includes those amounts in the revenue requirement used to set rates. Between general rate cases, Ameren Missouri tracks its actual expenditures against amounts included in rates. If it spends more, the Company is allowed to book the difference as a regulatory liability; if it spends less, the difference is booked as a regulatory asset. In the next general rate case, Ameren Missouri is to include an amortization of any regulatory asset balance in its revenue requirement used to set rates, and any regulatory liability lowers customer rates in the same way. The trackers have ensured that Ameren Missouri's rates do not reflect more, or less, than its actual, prudently-incurred costs to comply with the Commission's rules. The trackers thus represent a win-win situation for both Ameren Missouri and its customers.

Because the trackers' benefits flow both ways, they would seem to be the type of regulatory mechanism all parties to this case would embrace and support. Yet Staff, OPC, and MIEC each oppose continuation of both trackers. Those parties argue the purpose of the trackers – to allow Ameren Missouri to gain experience regarding how much it will cost to comply with the Commission's rules – already has been fulfilled because the Company has completed full

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[400] *Report and Order*, Case No. ER-2008-0318, pp. 32-49.
[401] *Report and Order*, File No. ER-2010-0036, pp. 58-65; *Report and Order*, File No. ER-2011-0028, pp. 14-19; and *Report and Order*, File No. ER-2012-0166, pp. 102-07.

vegetation management and infrastructure inspection cycles. They also point to statements in past rate case orders that the Commission never intended the trackers would be permanent.[402]

But the Commission should reject these arguments for at least three reasons. First, each party's opposition appears to be rooted in a generalized dislike for, and opposition to, deferral mechanisms. Second, the parties opposing the trackers ignore the fact Ameren Missouri's costs to comply with vegetation management and infrastructure inspection rules fluctuate from year-to-year due to factors beyond the Company's control, and will continue to do so into the future. Finally, the opponents ignore the fact rules governing vegetation management and infrastructure inspection include language strongly indicating the Commission intends trackers would be used to facilitate a full reflection of the costs utilities incur to comply with those rules in rates.

In his rebuttal testimony in support of the tracker, Mr. Wakeman states:

> The cost of trimming has varied and will continue to vary based on a number of factors outside the Company's control. These factors include, but are not limited to, the fluctuation of required distribution line miles and their classification on an annual basis; continually evolving federal requirements for transmission facilities; varying vegetation growth rates experienced annually; varying rates of tree mortality based on environmental factors; new or increasing threats from disease and insects, such as we are seeing from the Emerald Ash Borer; and changes in the cost of labor, equipment and fuel. The trackers address these cost variations (which the Company cannot avoid or control) arising from mandatory operations required by the Commission's rules.[403]

Ameren Missouri's annual expenditures to comply with the vegetation management rule illustrate Mr. Wakeman's point. Although there have been instances where expenditures were less than the prior year, when they occur those variances were minimal. Overall, compliance costs have shown a marked upward trend over the period 2008 through the end of the true-up period in this case. Table 3 on page 18 of Exhibit 513 shows annual vegetation management expense increased from $49.2 million in 2008 to approximately $55.2 million in 2013, although

[402] *See, e.g.*, *Report and Order*, File No. ER-2012-0166, p. 107.
[403] Ex. 46, p. 3, l. 12-21 (Wakeman Rebuttal).

Company witness Laura Moore estimated actual expenditures for vegetation management through December 31, 2014, would likely be closer to $56 million.[404] Ms. Moore further testified that annual expenditures for vegetation management and infrastructure inspection have increased each year since 2012.[405] Without the trackers, it is unlikely Ameren Missouri would have been able to reflect a significant portion of those increased costs in rates, even though the expenditures were mandated and factors causing the increases were beyond the Company's control.

In addition, rules governing both vegetation management and infrastructure inspection seem to contemplate the use of a tracker mechanism to ensure any difference between actual compliance costs and costs that can be reflected in rates. This is clear from the fact each of those rules includes a provision that states:

> In the event an electrical corporation incurs expenses as a result of this rule in excess of the costs included in current rates, the corporation may submit a request to the commission for accounting authorization to defer recognition and possible recovery of these excess expenses until the effective date of rates resulting from its next general rate case, filed after the effective date of this rule, using a tracking mechanism to record the difference between the actually incurred expenses as a result of this rule and the amount included in the corporation's rates . . . Parties to any electrical corporation request for accounting authorization pursuant to this rule may ask the commission to require the electrical corporation to collect and maintain data (such as actual revenues and actual infrastructure inspection expenses) until such time as the commission addresses ratemaking for the deferrals. The commission will address the ratemaking of any costs deferred under these accounting authorizations at the time the electrical corporation seeks ratemaking in a general rate case.[406]

While language in a rule specifically providing for a tracker may not be unique, it certainly is exceptional. Indeed, when asked if she knew of any other mandate that includes a similar provision for deferral and amortization of compliance costs, Staff's witness Lisa

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[404] Ex. 32, p. 9, l. 8-11 (Moore Surrebuttal).
[405] Tr. p. 923, l. 25 to p. 924, l. 4.
[406] 4 CSR 240-23.020(4) and 4 CSR 240-23.030(10).

Hanneken testified she did not.[407] Moreover, although the rules' language is permissive with respect to whether a tracker will be authorized, the fact the rules specifically provide for a tracker strongly suggests the Commission recognized the cost burdens the vegetation management and infrastructure inspection rules would impose and determined those burdens warranted special regulatory treatment.

No party opposing these trackers has presented any evidence the vegetation management and infrastructure inspection trackers are not working exactly as designed and intended. No such evidence exists, because during the more than five years the trackers have been in place, they have ensured Ameren Missouri was able to reflect all its prudently-incurred compliance costs while also ensuring customer rates do not reflect more than is spent on compliance (there have, in fact, been amortizations of regulatory liabilities when less was spent, which lowered customer rates).

In addition to deciding whether the trackers should be continued, the Commission also must decide the amount of vegetation management and infrastructure inspection expense to reflect in the revenue requirement used to set rates. The parties' estimates of compliance costs vary significantly, and illustrate the real potential for reflecting too little or too much in rates if the trackers are discontinued. Because costs have increased each year since 2012, Ameren Missouri believes actual vegetation management and infrastructure inspection costs incurred through the end of the true-up period – approximately $62.4 million[408] – represents the best estimate of what these costs will be during the period rates set in this case are in effect. In contrast, the cost estimates proposed by Staff, OPC, and MIEC – each of which is based on an average of historic cost data – are much lower. Staff's estimate, a normalized amount based on a

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[407] Tr. p. 935, l. 9-17.

[408] The appropriate base for the vegetation management tracker is $56 million and for the infrastructure inspections tracker is $6.4 million. Ex. 32, p. 9, l. 5-11 (Moore Surrebuttal).

three-year historical average, is approximately $2.1 million less; MIEC's estimate, normalized using a five-year historical average, is $2.6 million less; while OPC's estimate, normalized using a two-year historical period for infrastructure inspection and a 62-month period for vegetation management, is $4.4 million less.[409] If the trackers are eliminated, and assuming compliance costs do not change during the period rates set in this case are in effect, adopting Staff's, OPC's, or MIEC's estimates likely would result in rates failing to reflect the Company's compliance costs by the differences indicated in the preceding sentence. Such a result is not fair; and, perhaps more importantly, it is not necessary, because retaining the trackers eliminates any possibility vegetation management and infrastructure compliance costs will fail to accurately be reflected in rates.

XI. STREET LIGHTING

A. The Commission cannot mandate or require that the Company sell its street lights to the Cities.

The cities of O'Fallon, Missouri and Ballwin, Missouri ("Cities") assert that the Company's 5(M) Street and Outdoor Area Lighting – Company Owned tariff (5(M) tariff) is unjust and unreasonable because it does not require the Company to sell the Company-owned street lighting facilities that are used to serve a customer, to that customer. [410] Cities ask the Commission to change Ameren Missouri's 5(M) tariff to provide that the "[c]ustomer shall have the right and option to purchase…only that portion of the Street Lighting System determined by the Company in use and useful and devoted exclusively to furnishing street lighting within the corporate limits of the Customer.["][411] Cities claim they are entitled to this relief because they claim (mistakenly) that they have been paying for Company-owned street lighting facilities, they

[409] Tr. p. 922, l. 25 to p. 923, l. 18.
[410] *Statement of Positions of Intervenors City of O'Fallon and City of Ballwin, Missouri*, p. 2, EFIS Item 393.
[411] Ex. 850, Exhibit D (Bender Direct).

mistakenly claim that it is simple and cheap to leave the street lighting facilities in place and transfer ownership to them, and they want to own the facilities so that they can take street lighting service under the Company's 6(M) Street and Outdoor Area Lighting – Customer-Owned tariff (6(M) tariff).

i. <u>Cities have not acquired any interest in the Company's property.</u>

City of O'Fallon witness, Steve Bender, complained in direct testimony that because Ameren Missouri refused to negotiate the sale of its street lighting facilities, O'Fallon would "have to indefinitely continue to pay for the lighting fixtures under the 5(M) rates even though it may have already paid substantially more than the value of those fixtures."[412] Mr. Bender also asserted that "over a ten year period the City has paid approximately $1,850.00 per light fixture."[413] City of Ballwin witness, Robert Kuntz, also complained that the 5(M) tariff requires the Cities to "pay the costs of the facilities over and over" and that the Company "is enjoying a windfall for those fixtures that the City has paid excessive costs for over the last several decades."[414] Counsel for Cities even suggested the same in his opening statement, "the Cities have been paying, over and over, in these 5M rates, for these streetlights."[415]

The Cities have *not* paid for the street lighting facilities, and have not purchased any interest in them. Just as this Commission explained to the Municipal Group in Ameren Missouri's 2010 rate case, Cities misunderstand the nature of the charges they have been paying.[416] There, the Commission explained that paying pole and span charges under street lighting tariffs did not mean the members of the Municipal Group would eventually own the

[412] Ex. 850, p. 2, l. 11-12.
[413] Ex. 850, p. 3, l. 16. *Note*, City of Ballwin witness, Mr. Robert Kuntz, endorsed Mr. Bender's direct testimony. Ex. 852, p. 1, l. 29-34. (Kuntz Direct).
[414] Ex. 853, p. 3, l. 30 to p. 4, l. 2. (Kuntz Surrebuttal).
[415] Tr. p. 171, l. 11-15.
[416] *Report and Order*, File No. ER-2011-0028, ¶ 9.

poles and spans.[417] Similarly, paying (5M) street lighting charges for any number of years does not give the Cities any current rights in the street lighting fixtures, or the right to purchase the Company's street lighting facilities in the future, because Cities have not been paying for property. To the contrary, they have been paying for *service*. As explained earlier, the U. S. Supreme Court held 90 years ago that a customer has no interest, legal or equitable, in a public utility's property, and our Missouri Supreme Court ruled based on that precedent as many as 80 years ago. *Board of Public Utility Comrs, supra* (which was cited by the Missouri Supreme Court for this proposition).

ii. <u>The Company cannot and should not leave its street lighting facilities in place and sell them to Cities.</u>

Cities also could not be more wrong about the complexities, risk and expense involved in the proposed transfer of ownership and control of the Company's street lighting facilities to them. Mr. Kuntz testified that Cities were interested in, "only acquiring the light fixtures themselves…Ameren [could] retain control over maintenance of the other parts of the distribution system, if Ameren wished" and "it is my understanding that the facilities that form the City's street lighting infrastructure, which in some cases attached to distribution poles, are essentially separate and apart from Ameren's general distribution system."[418] He also could not think of any reason why Ameren Missouri and Ballwin would not share pole space.[419] He also believed Ameren Missouri would benefit by avoiding the costs of removing and disposing of its light fixtures.[420]

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[417] *Id.*, p. 61, ¶10.
[418] Ex. 853, p. 2, l. 7-9; 12-14.
[419] Ex. 853, p. 2, l. 21-23.
[420] Ex. 853, p. 3, l. 16-18. *Note*, Mr. Bender concurred with Mr. Kuntz's surrebuttal testimony. Ex. 851, p. 1, l. 24-28.

The Cities' proposal to acquire only light fixtures is not workable because as the Company's witness, Mr. Wakeman, explained, under the 6(M) tariff, the customer must own the entire conductor system, including wires, poles and light fixtures, up to a disconnection point at which the Company provides only electricity.[421] Nor is it correct that the Company's distribution system for 5(M) lighting is separate from the street lighting facilities, or, as Cities' counsel suggested, that "Ameren doesn't have to do a thing. They don't have to touch a light. They don't have to pay to have anything removed. They can simply just transfer for fair market value."[422] The Company cannot simply leave all existing street lighting facilities including wiring in place and transfer ownership and control to the Cities. The Company's street lighting facilities that provide service to Cities under the 5(M) tariff are an integrated part of the Company's distribution system. Simply leaving the street lighting facilities as-is and selling to the Cities would create serious safety and reliability concerns for the Company because the street lighting facilities share space with and are directly connected to other energized pieces of Company-owned equipment that serve the Company's other customers.[423] Serious hazards and risks are presented if persons other than specially trained and skilled Company personnel are accessing the Company's distribution system.[424]

For example, a set of Company-owned streetlights may be fed by a 120-volt cable that runs directly into a 12,000-volt transformer that serves a number of other customers in the neighborhood. If the street lighting facilities were sold and transferred to Cities' ownership and control, disconnects would have to installed so that the Cities could cut power to the lights for maintenance and other purposes without the Cities having to access the Company's high-voltage

[421] Tr. p. 1830, l. 9 to p. 1831, l. 2.
[422] Tr. p. 173, l. 25 to p. 174, l. 3. What exactly the Cities mean by "fair market value" is unclear.
[423] Tr. p. 1804, l. 6-25.
[424] Tr. p. 1832, l. 22 to p. 1833, l. 17.

transformer. Likewise, cables powering the lights would have to be removed and relocated from the trenches or conduit that also contain Company-owned high-voltage and secondary cables, to eliminate safety and reliability concerns that would arise.[425] Simply put, as presently configured, there is "no way to shut the power off"[426] to the Company's street lighting facilities without working in the Company's distribution infrastructure. The facilities could not be transferred unless and until the cable that forms part of the street lighting facilities to be sold were moved out of Company trenches and disconnect switches were installed to permit the power to the facilities to be cut without accessing Company owned distribution equipment. There are additional complications where 5(M) street lighting is provided via fixtures mounted on the Company's distribution poles. Obviously, in such a case, the Company could not transfer ownership of the pole to Cities, and it could not simply transfer ownership of the street lighting fixture located on the pole to Cities, because it would not be safe for them to have Cities working within approach distance of Company high-voltage conductors.[427]

Nor, as Cities' counsel suggested, could the Company transfer its wiring in place to Cities and simply "work out" maintenance issues with Cities,[428] because as Mr. Wakeman explained, the 6(M) tariff is not designed to provide revenues to cover costs Ameren Missouri would incur if it performed maintenance related to said wiring on customer-owned street lighting facilities.[429]

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[425] Tr. p. 1809, l. 7 to p. 1811, l. 13; p. 1814, l. 18 to p. 1816, l. 4.
[426] Tr. p. 1819, l. 16 to p. 1820, l. 13.
[427] Tr. p. 1836, l. 4-21.
[428] Tr. p. 1827, l. 2 to p. 1828, l. 19.
[429] Tr. p. 1831, l. 15 to p. 1832, l. 5.

iii. The Commission does not have the statutory authority to order the Company to sell its street lighting facilities to Cities.

Regardless of whether the Company-owned street lighting facilities could be transferred, as-is, the Commission still cannot order the relief requested because the Commission does not have the statutory authority to mandate that the Company sell its property.

Cities make a three-part argument that the Commission has the authority to mandate that Ameren Missouri sell its assets to them:

- If Cities elect to terminate their 5(M) service, it would cost less for the Company to simply sell its street lighting facilities, in situ, to Cities, so that they could take service under the 6(M) rates, than for the Company to incur the costs to remove the facilities and scrap them, and it would cost less for the Cities to buy the used existing street lighting facilities than to buy and install new street lighting facilities, and Cities have been paying for the street lighting facilities for years anyway, so they should have the right to buy them.

- Since it is uneconomic and unfair for Ameren Missouri not to agree to sell its streetlight facilities to the Cities it must be unjust and unreasonable.

- If Ameren Missouri's actions in refusing to sell, and in planning to remove and dispose of the facilities, are unjust and unreasonable, the Commission has the authority, at §393.140(5) RSMo, to determine and prescribe the just and reasonable acts and regulations that Ameren Missouri must do and observe.

The first problem with Cities' argument is that the Cities have provided no evidence that the Company's refusal to sell Company property, upon Cities' termination of their 5(M) contracts (which termination has not yet occurred[430]), is unjust or unreasonable. Utilities must provide safe and adequate *service* at just and reasonable rates and not more than allowed by law or by the Commission. §393.130.1. Utilities cannot grant any undue or unreasonable preferences to any *customer* or to any particular description of *service* or subject any particular *customer*, locality or description of service to any undue or unreasonable prejudice or disadvantage. §393.130.3. These provisions are, "merely declaratory of the common law

[430] Tr. p. 1864, l. 3-6.

rule…requir[ing] one engaged in a public calling to charge a reasonable and uniform price or rate to all persons for the same *service* rendered under the same or substantially similar circumstances or conditions" (emphasis added). [431] These provisions applicable to a public utility's duty to provide service in no way can be read to force a utility to sell property to a potential buyer that has no legal or equitable interest in the property, just because the sale would benefit the buyer. Even if a reasonableness (in the general sense of the word) standard applies to the Company's decision to sell or not sell, Mr. Wakeman's testimony shows that the Company's reluctance to sell its property on Cities' terms is entirely reasonable.

More importantly, it appears the Cities are contemplating *terminating* their contracts for 5(M) service, although neither has yet told Ameren Missouri that it has chosen to terminate its contracts and there is no evidence that either city is going to terminate its contract. IF they terminate their contracts, the Company is by definition, and by the *Cities'* choice, no longer being required to provide a service, and the Cities, at that point, are no longer customers. Upon termination, the just and reasonable standard, and the Commission's authority under §393.140(5) to remedy unjust or unreasonable acts or regulations of a utility by "prescrib[ing] the just and reasonable rates and charges…for service…and the just and reasonable acts and regulations to be done and observed" simply no longer applies to Ameren Missouri's dealings or refusal to deal with Cities, because Ameren Missouri's property is no longer being required to provide service to them.

iv. <u>The Company may dispose of property that is not necessarily or useful without Commission approval</u>.

Nor at the point of termination of Cities' 5(M) contract will Ameren Missouri be required to secure the Commission's approval to dispose of its street lighting facilities in a manner that

[431] ***State ex rel. Laundry, Inc. v. Pub. Serv. Comm'n***, 327 Mo. 93, 34 S.W.2d 37 (Mo. 1931) (emphasis added).

Cities deem "economic." When the 5(M) contract is terminated, the Company-owned street lighting facilities will no longer be necessary or useful in the performance of its duties because the Company's duty to devote those facilities to provide utility service terminated when the Cities terminated their 5(M) contracts. Although §393.130.1 RSMo generally provides that public utilities may not dispose of any portion of their franchise, works or system without the Commission's approval, it also expressly provides:

> Nothing in this subsection contained shall be construed to prevent the sale, assignment, lease or *other disposition* by any…public utility…of property which is not necessary or useful in the performance of its duties to the public[.]

It is important to note that §393.130.1 does *expressly* deal with the PSC's authority with regard to sales of utility property: "[n]o…electrical corporation…shall hereafter sell…any part of its franchise works or system…without having first secured from the commission an order authorizing it to do so…[.]" The Commission, however, "is a body of limited jurisdiction[432] and has only such powers as are expressly conferred upon it by the statutes and powers reasonably incidental thereto."[433] Section 393.190.1 RSMo only grants the Commission statutory authority to approve a voluntary sale, where the seller has *agreed* to sell and sought Commission approval, because it refers to approval after an affirmative, voluntary act *by the seller*. That is, it is the seller that must petition for and secure the PSC's order. In dismissing Cities' recent complaint that sought the same relief Cities seek now, the PSC properly concluded that, "[s]ection 393.190 RSMo does not allow the Commission to order Ameren Missouri to sell property it does not wish

[432] Perhaps the more appropriate term, post-***J.C.W. ex rel. Webb v. Wyciskalla***, 275 S.W.3d 249, 254 (Mo. banc 2009), is "authority" or "statutory authority," rather than jurisdiction. ***State ex rel. Praxair, Inc. v. Mo. PSC***, 344 S.W.3d 178, 2011 Mo. LEXIS 201 (Mo. 2011); *but see*, ***Sharp v. Kan. City Power & Light Co.***, 2015 Mo. App. LEXIS 19, *13. (Mo. App. W.D. Jan. 13, 2015), where the Court of Appeals recently referred interchangeably to the PSC's "limited jurisdiction" and the limited statutory authority granted to the PSC.
[433] ***State ex rel. and to Use of Kansas City Power & Light Co. v. Buzard***, 168 S.W.2d 1044, 1046 (Mo. 1943); *Sharp* at *13.

to sell."[434] If §393.190, the statute *specifically* addressing the PSC's authority with regard to the sale of utility property, does not permit the PSC to force a utility to sell property, then §393.140(5), a statute that does not even reference the sale of utility property, cannot reasonably be read to confer on the PSC the authority to force a utility to sell its property.

v. The Commission does not have statutory authority, nor is it just and reasonable, to order Ameren Missouri to sell its property involuntarily.

Finally, the Commission cannot mandate that Ameren Missouri sell its street lighting facilities to the Cities because the mandate amounts to an appropriation of the Company's property under circumstances where the Company is not willing to sell. To appropriate private property for public purposes, an entity with the power to condemn must file a condemnation petition.[435] Statutory authority to order property condemned rests only with the circuit court of the county where the property to be condemned is located. Further, since the Cities are expressly prohibited by §71.525 RSMo from condemning Ameren Missouri's property,[436] it also cannot possibly be "just and reasonable" within the meaning of the PSC's powers under 393.140(5) for the Commission, in ordering "just and reasonable acts…to be done," to order Ameren Missouri to sell its property to Cities involuntarily.

Even if the Cities turn around and request service under 6(M) tariff, that tariff does not require that the Company sell street lighting facilities to the customer for the customer to own. How, then, do customers ever acquire street lighting facilities so that they can take service under the 6(M) tariff? Probably exactly as the City of O'Fallon's ordinance addressing new street

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[434] *Order Granting Motion to Dismiss for Failure to State a Claim For Which Relief Can Be Granted*, File No. EC-2014-0316, p. 3.
[435] §523.010.
[436] Subject to an exception not applicable to Cities, §71.525 RSMo provides, "no city, town or village may condemn the property of a public utility, as defined in section 386.020, RSMo…if such property is used or useful in providing utility services and the city, town or village seeking to condemn such property, directly or indirectly, will use or proposes to use the property for the same purpose, or a purpose substantially similar to the purpose that the property is being used by the public utility[.]"

lighting installations provides, by requiring developers to construct streetlights in a way that conforms to Ameren Missouri's 6(M) lighting requirements.[437]

Even if the Commission had the authority to adopt Cities' proposed changes to the Company's 5(M) tariff, and to force a sale of the Company's street lighting facilities, there are good policy reasons for holding off on taking such extreme measures. Cities want to force a sale so that they will own street lighting facilities and can take service under the Company's 6(M) rates. As explained in section B, below, the Commission may consider shifting revenue from 5(M) to 6(M), increasing 6(M) rates to move towards that subclass's actual cost of service. A shift to cost-based 6(M) rates may, if Cities were to purchase street lighting facilities, and subsequently: 1) incur what could be significant expense to disentangle the street lighting facilities from the Company's integrated distribution system, 2) be responsible for costs associated with replacement and ongoing maintenance of said facilities, and 3) experience disproportionately rising 6(M) rates, mean that the purchase of street lighting facilities may not turn out to produce the savings they anticipate.

B. The Commission may wish to consider a revenue-neutral adjustment between customer-owned and Company-owned lighting rates, over a sufficient period of time to avoid rate shock to 6(M) customers.

For purposes of the CCOSS performed by Mr. Warwick for this case, the three lighting classes, 5(M), 6(M) and 7(M), were combined.[438] The Company's CCOSS, like that of Staff and MIEC, showed that the lighting class, as a whole, has rates that closely reflect its underlying costs.[439] However, Mr. Bender alleged that that the Company's 5(M) tariff rates are excessive

[437] Tr. p. 1860, l. 12-22.
[438] Ex. 49, p. 5, l. 6-10 (Warwick Direct).
[439] Ex. 9, p. 39, l. 16-19 (Davis Rebuttal).

and expressed the desire to take street lighting service under the 6(M) tariff [440] As a result, the Company's Economic Analysis and Pricing Manager, William Davis, further analyzed the lighting-related data used in class cost of service study performed by Mr. Warwick.[441] What Mr. Davis found, using the exact same cost allocation methods used in the general CCOSS, but at a more granular level particular to each lighting class, was that while 5(M) rates are currently 11% above cost of service, 6(M) rates are significantly below cost of service.[442] Mr. Davis filed rebuttal testimony highlighting his analysis, not (as Cities' counsel suggested) in an effort to create a barrier for a customer wishing to take 6(M) service, but to inform 5(M) customers, like Cities, who might be looking for ways to take service under 6(M) rates, that a future shift in 6(M) to cost-based rates would materially decrease the benefits of a switch to 6(M).[443] In addition, any revenue neutral reduction to 5(M) rates will result in an immediate cost reduction to the Cities (and all other 53,500 5(M) customers[444]) compared to a rate increase that is implemented without a revenue neutral shift.

Setting cost-based rates for 5(M) and 6(M) would require a shift of about $3.9 million from 5(M) to 6(M).[445] If the shift were made all at once, 6(M) rates would roughly double, while 5(M) rates would decrease by 11%.[446] Since 6(M) customers might experience rate shock if all $3.9 million were shifted from 5(M) rates to 6(M) rates, at once, the Commission may want to consider moving the lighting rate schedules to full cost-based rates, over a sufficient period of time to avoid rate shock.[447] Regardless of the period over which the shift might be made,

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[440] Ex. 850, p. 2, l. 7-10 ("Accordingly, the City has intervened in this rate case to direct the Commission's attention to the excessive rates O'Fallon is paying for street lighting services[.]").
[441] Tr. p. 1841, l. 20 to p. 1842, l. 7; Ex. 9, p. 40, l. 14 to p. 41, l. 2.
[442] *Id.*; Tr. p. 1841, l. 21 to p. 1843, l. 24.
[443] *Id.*; Ex. 9, p. 41, l. 3-11.
[444] There are approximately 1,500 6(M) customers.
[445] Ex. 9, p. 40, l. 14 to p. 41, l. 2.
[446] *Id.;* Tr. p. 1472, p. 21-24.
[447] Ex. 9, p. 41, l. 12-15.

making 5(M) and 6(M) rates more comparable in terms of cost is advisable, given the direct competition between the 5(M) tariff and the 6(M) tariff.[448] In addition, if LED street lighting is implemented in the future, aligning both 5(M) and 6(M) rates on a cost-based basis would help ensure that Company-owned and customer-owned LED street lights are priced to promote efficient economic decisions between 5(M) and 6(M).[449]

C. The Commission should not eliminate termination fees from the Company-owned lighting rate, because the fee is necessary to recover costs associated with early termination, and because it serves as an important disincentive to uneconomic allocation of resources.

The Company's 5(M) $100 early termination fee of 5(M) service and out of contract termination of 5(M) service with subsequent request for re-instatement of same within a finite period is at issue in this case because Cities have misunderstood the nature and application of the $100 fee. First, Cities misunderstood the fee to reflect the value of a street lighting fixture and, based on that misunderstanding, complained that they pay, "almost double this amount each year of service for the cost of the fixture."[450] As explained in section A, above, Cities are paying for service, *not* the cost of a fixture. The fee does not represent the full cost of the facilities for which service is being terminated.[451] Next, Cities mistakenly conclude that, "if the City were to notify Ameren of its intent to terminate under the 5(M) tariff, O'Fallon might have to pay the $100 fee for each of the approximate 4,442 fixtures…which would cost the City as much as $444,200.00."[452] They urge the Commission to strike the fees, because when added to the costs to purchase their own new lighting facilities, the total costs "are a significant and unreasonable

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[448] *Id.*, l. 19 to p. 42, l. 4.
[449] *Id.*
[450] Ex. 850, p. 3, l. 29 to p. 4, l. 2. Recall that Ballwin's witness, Mr. Kuntz, endorsed the direct testimony of Mr. Bender.
[451] Ex. 9, p. 43, l. 7-18.
[452] Ex. 850, p. 5, l. 18-21.

barrier to the [Cities] for changing to the 6(M) tariff."[453] At the hearing, however, Cities each admitted that if they were to terminate their 5(M) service today, the $100 fee would apply to less than 10% of the lights.[454] The termination fee should not be eliminated from the Company's 5(M) tariff, because although it may be a disincentive to termination of 5(M) service, it is a disincentive the Cities agreed to when the Cities entered into 5(M) contracts with the Company.

More importantly, the fee should not be eliminated because it is reasonable and serves a number of important purposes. Under the Company's 5(M) tariff, when the customer selects lamps and fixtures from the standard equipment offered by the Company, the Company provides all poles/posts and cables, provides the lamps and fixtures, installs the lighting system, and thereafter inventories, furnishes, maintains and delivers electric service to the street lighting facilities, with the customer paying only the specific monthly charges associated with the lamp and fixture the customer has requested.[455] If the Company installs standard facilities to serve the customer, the Company requires that the customer enter into at least a three-year contract, and if the Company installs post-top luminaries to serve the customer, the customer must enter into at least a ten-year contract.[456] Because the customer is paying its monthly fee while the Company must pay the costs to inventory, replace and maintain the lamps, if the customer requests a change in the size of type of lamp that the Company would not otherwise be making, the customer is required to pay a $100 conversion fee.[457] Echoing the contract period, if the customer wants to terminate lighting service within three years of the installation of a lamp to which service would be terminated, or within ten years of the installation of post-top luminaries

[453] *Id.*, l. 21-23.
[454] Tr. p. 1861, l. 20-24; Tr. p. 1864, l. 15-18.
[455] Tr. p. 1845, l. 5 to p. 1846, l. 24; 5(M) tariff, sheet 58.4.
[456] 5(M) tariff, sheets 58, 58.1, 58.2 and 58.4.
[457] 5(M) tariff, sheet 58.4, ¶4.

to which service would be terminated, the customer is required to pay the Company $100.[458] If the request for termination is made after the applicable termination fee periods, but the customer returns to the Company and requests lighting services within twelve months after the Company has actually removed the terminated lighting facilities, the customer is required to pay the removal fee for all facilities previously removed, prior to the Company making the new installations.[459]

The $100 termination fee is reasonable because it offsets the Company's cost to remove the facility being terminated and the loss of the remaining life of the item.[460] In addition, without the fee, a 5(M) customer has little, if any, disincentive to terminate service early, which causes the Company to incur the cost of early removal, then immediately turning around and asking to reestablish service, which would also cause the Company to incur unexpected costs.[461] It is entirely rational for the Company to want to discourage customers from requesting a change in lighting fixtures not long after the fixtures have been installed, or from terminating service prior to the expiration of their contract period, in order for the Company to avoid, if possible, costs to replace lamps or remove fixtures, that the Company would not have incurred in the absence of such request or termination.

XII. UNION PROPOSALS

As in prior rate cases, the International Brotherhood of Electrical Workers Local 1439, AFL-CIO ("IBEW") intervened and filed testimony supporting the Company's request for a rate increase, but raised concerns about Ameren Missouri's internal workforce needs and its aging

[458] 5(M) tariff, sheet 58.5, ¶7.
[459] *Id.*
[460] *Id.*; Ex. 9, p. 43, l. 7-18.
[461] Tr. p. 1840, l. 17 to p. 1841, l. 16.

infrastructure. With respect to the internal workforce,[462] IBEW has proposed that the Commission mandate specific hiring protocols and grant the Company a training-specific rate allocation. With respect to infrastructure, IBEW has proposed that the Commission mandate quarterly Company reporting on system load, optimal replacement of certain equipment, and spending, and that the Commission grant the Company an infrastructure-specific rate allocation.

IBEW has not shown that Ameren Missouri's hiring practices, or the state of its infrastructure, are causing the Company to fail to provide safe and adequate service. Nor has IBEW shown that a failure to implement IBEW's specific recommendations would lead to a failure to provide safe and adequate electric service. Whatever role the Commission may have in ensuring that the utilities it regulates meet their obligation to provide safe and adequate service, that role is not implicated on the record in this case. There continues to be no justification for IBEW's proposals and, as in prior rate cases, the Commission should continue to refuse[463] to inject itself into Company personnel decisions. As to infrastructure reporting, the Commission should reject IBEW's recommendations because competent and substantial evidence shows that the Company already recognizes the need to replace aging infrastructure, and already provides adequate reliability-related reports to the Commission, so the additional reporting will add costs, but provide no benefits.

The special rate allocations proposed by IBEW should also be rejected. The best reason not to add an additional $11.1 million for training to the rate increase requested by the Company is that Company did not include the requested additional amount in its direct testimony delineating the rate increase requested in this case. The so-called training allocation is really a

[462] By "internal workforce," IBEW means a "permanent direct workforce" including job classifications relating to Ameren Missouri's distribution and transmission systems, such as linemen, technicians, meter installers, substation mechanics, and underground workers. Ex. 800, p. 7, l. 17-23 (Walter Direct).
[463] *See, Report and Order,* File No. ER-2008-0319, p. 112-113; *Report and Order,* File No. ER-2010-0036, p. 70, ¶4, pp. 71-72; and *Report and Order*, File No. ER-2011-0028, p. 103, ¶4, pp. 104-105.

mandate (for which there is no authority) to add 111 workers to the Company's internal workforce over the next three years. While the addition of 111 workers would almost certainly benefit IBEW, the Company isn't at all certain it would be prudent to add the 111 workers, or that it could offer them long-term employment.

The separate special infrastructure allocation must be rejected because it would almost certainly violate statutory prohibitions against basing rates on construction work in progress ("CWIP").

A. The Commission cannot mandate how the Company addresses its workforce needs, and even if there were circumstances where it could, the Commission should not mandate that the Company address its workforce needs as IBEW proposes.

IBEW made the following specific proposals with respect to the Company's workforce:

- That the Commission demand that Ameren Missouri fill all jobs, internal or outsourced, from within its service territory first, then from within the State of Missouri, but "never offshore."[464]

- That that the Commission make a special rate allocation of, i.e. authorize additional Company rate increases in the amount of, $11.1 million per year in 2015, 2016 and 2017, and require Ameren Missouri to use the allocations to train exactly 37 apprentices each year for various job classifications.[465]

The Commission should reject IBEW's proposal that the Commission mandate how, and from where, the Company should fill all jobs. IBEW offered no testimony or other evidence, nor even suggested, that the current pool from which the Company fills internal or outsourced jobs has any effect on the Company's ability to provide safe and adequate service. Although the

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[464] Ex. 800, p. 9, l. 18-20. (Walter Direct).

[465] *Id., l. 20-23;* Tr. p. 1033, l. 23 to p. 1034, l. 6. The Commission cannot grant "additional rate increases." It could only add $11.1 million to the Company's revenue requirement in this case. But once the Commission increases the Company's revenue requirement, it effectively will be setting higher rates for customers for the electric service the customers receive. As discussed earlier in this Brief, customers don't pay for particular costs. Absent some kind of voluntary agreement on the Company's part to dedicate "extra" funds received through rates to some specific purpose, the Commission has no mechanism to "require" the Company to use these "funds" to hire the 111 IBEW members IBEW seeks. The Company doesn't want the extra funds, and isn't agreeing to accept them in order to dedicate them to a particular purpose.

Company has an obligation to provide safe and adequate service, the Commission does not have the authority to dictate the Company's hiring practices, and this is even more clearly so given the complete lack of any evidence – indeed any allegation that – the Company is not in fact providing safe and adequate service. This is because:

> The powers of regulation delegated to the Commission are comprehensive and extend to every conceivable source of corporate malfeasance. Those powers do not, however, clothe the Commission with the general power of management incident to ownership. The utility retains the lawful right to manage its own affairs and conduct its business as it may choose, as long as it performs its legal duty, complies with lawful regulation, and does no harm to public welfare.[466]

In support of a training-specific rate allocation, IBEW offered the testimony of Michael Walter, IBEW's business manager. Mr. Walter asserts that reduced staffing levels have left the internal workforce short-handed and have caused a pile-up of work.[467] He also claims, based on IBEW surveys of the internal workforce,[468] that 35% of the Company's utility workers will be retiring in the next five years.[469] He concludes with the dire prediction that if the Company does not start "hiring and training their replacements in large numbers now, the Company's vaunted reliability will not survive."[470]

Despite his grim direct testimony, at hearing Mr. Walter admitted that Ameren Missouri is currently providing very reliable, and consistently reliable, service.[471] Although he plainly prefers increasing the Company's internal workforce rather than hiring contractors,[472] and testified that he believes the internal workforce's quality of work is better,[473] he admits that he

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[466] ***State ex rel. Harline v. Public Serv. Comm'n***, 343 S.W.2d 177, 182 (Mo. App. K.C. 1960).
[467] Ex. 800, p. 4, l. 15-25.
[468] Ex. 800, Union Exhibits 800-1 to 800-3.
[469] Ex. 800, p. 4, l. 28 to p. 5, l. 1.
[470] Ex. 800, p. 5, l. 8-10.
[471] Tr. p. 1024, l. 4-10.
[472] *See* Ex. 800, p. 7, l. 17 to p. 8, l. 10.
[473] Tr. p. 1041, l. 16-21.

cannot quantify that belief.[474] In addition, he would not say that "the outsourcing contractors are not quality," he admits they are "all well trained, as well as we are,"[475] "in some cases [have] more lengthy training programs than we do[,]"[476] and admits that the external job force gets the job done as timely as expected.[477] Although he believes his data about Company use of contractors showed that contractors were being hired to perform "normal sustained work" rather than seasonal bulges, he concedes that backlogs in work are inherent because there's always something that needs to be done.[478]

While in his direct testimony Mr. Walter pointed the Commission to a 2013 Center for Energy Workforce Development ("CEWD") prediction that almost 55% of "the workforce" may need to be replaced in five years,[479] Mr. Walter appears not to have noticed that the five-year, 55% figure actually applies to "*all* jobs in the company, such as supervision, clerical, accounting and information technology, as well as the key job categories [of engineers, plant/operators, line workers and technicians]."[480] With respect to those "key job categories", CEWD actually predicts a need to replace not 55%, but 36% of those workers over the next five years.[481] More importantly, Mr. Walter admits that he has *no* data or evidence, other than his personal experience, to support his belief that a failure to replace every single employee lost through attrition will have an effect on future reliable safe service.[482] Yet contrary to his position on the need to keep up with attrition, he admits that advances in technology do sometimes mean that

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[474] *Id.*, l. 12-15.
[475] Tr. p. 1044, l. 13 to p. 1045, l. 14.
[476] Tr. p. 1046, l. 8-13.
[477] Tr. p. 1045, l. 19-25.
[478] Tr. p. 1049, l. 2 to p. 1050, l. 1.
[479] Ex. 800, p. 5, l. 4-5; Walter Schedule 4, pp. 2-3.
[480] Ex. 800, Walter Schedule 4, p. 3.
[481] *Id.*
[482] Tr. p. 1027, l. 4-23.

fewer personnel are needed.[483] He also admits that he has no data or evidence to suggest that a failure by Ameren Missouri to induct exactly 37 apprentices into internal workforce training programs in each of years 2015, 2016, and 2017 would cause it to be unable to provide safe and adequate service.[484] He is aware that the Company, without having requested any special allocation, already has plans to begin an apprenticeship program and an apprenticeship pre-qualification program.[485]

The Company's witness, David Wakeman, Senior Vice President of Operations and Technical Services, shed further light on the somewhat inaccurate and narrow perspective presented by IBEW. With respect to the allegation that a reduction in personnel has caused a "pile-up" of work, Mr. Wakeman testified that in fact, the Company has completed all mandatory and scheduled maintenance work, managing the completion of work through contractors when peaks in workload at various geographic locations would prevent the internal workforce from completing the work in a timely manner.[486] With regard to use of outside contractors, generally, Mr. Wakeman rebutted a number of IBEW's assertions regarding outside contractors, including that the Company's use has increased dramatically – Mr. Wakeman explained that in fact, there has been quite a fluctuation over the years, from 200 full-time-equivalent in 2008, down to six in 2011, and recently, back up to around 75.[487] He also explained that outside contractor costs do not vary more than the costs for union workers under the Company's collective bargaining agreement with IBEW,[488] and to the extent the costs have increased, the escalation is similar to that for internal labor costs.[489] He also explained that in the

[483] Tr. p. 1027, l. 24 to p. 1028, l. 2-5.
[484] Tr. p. 1029, l. 15-20.
[485] Tr. p. 1029, l. 22 to p. 1030, l. 17; p. 1031, l. 21-23.
[486] Ex. 46, p. 13, l. 3-13.
[487] Tr. p. 974, l. 8 to p. 975, l. 13.
[488] Tr. p. 980, l. 5-12.
[489] Tr. p. 981, l. 22 to p. 982, l. 6.

aggregate, the cost of outside contractors is comparable to the cost of the internal workforce, but it is still efficient for the Company to balance its workload using outside contractors because outside contractors are able to work over a wide geographic area where needed.[490] Finally, he explained that while he agreed that it is appropriate to use the Company's internal workforce for its normal and sustained workload, it is also important to use contractors for some of that work, to handle variations and fluctuations in workload specific to given areas at given times.[491]

With regard to retirements, the Company looks at projected retirement numbers on a quarterly, and sometimes monthly, basis.[492] Mr. Wakeman explained, however, that it is risky for the Company to make hiring decisions based on the future retirement projections reported in the survey, since factors such as changes in the economy and employees' retirement accounts can impact when employees actually retire, versus when they predict they will retire.[493] Instead, the Company projects retirements based on actual average retirement ages that the Company updates annually.[494] The bottom line is that the Company is paying attention to its workforce numbers, as evidenced by the facts that it currently has apprentices in multiple job classifications including underground, relay, substation and overhead, and has started a program at Florissant Valley Community College to pre-qualify individuals for an upcoming apprentice linemen class.[495]

Regarding attrition generally, and hiring to address peaks in workload, while Mr. Walter believes the Company should reflexively replace *all* employees lost through attrition,[496] Mr. Wakeman explained that the Company's approach is to actively evaluate workload and

[490] Tr. p. 983, l. 6-16.
[491] Tr. p. 985, l. 3-21.
[492] Tr. p. 989, l. 12-20.
[493] Tr. p. 990, l. 1-9.
[494] Tr. p. 990, l. 16 to p. 991, l. 5.
[495] Tr. p. 991, l. 24 to p. 993, l. 1.
[496] Tr. p. 1026, l. 23 to p. 1027, l. 9.

staffing in order to balance affordability and reliability, and to manage temporary peaks in workload by hiring qualified contractors on a short-term basis, rather than making an uneconomic decision to hire full-time employees to handle a short-term need.[497] In addition, technological improvements and reduced maintenance requirements for modern equipment have in recent years reduced internal workforce staffing needs by 20%.[498] Mr. Wakeman also explained that the Company does monitor attrition rates, as evidenced by the Company's plan to initiate several apprenticeship classes in 2015, but cannot make the decision to train and hire apprentices lightly, given the significant investment the Company must make in the lengthy training program required to bring on skilled workers.[499] Similarly, he explained the Company's reluctance to commit to hiring 111 apprentices, even if the Commission were to make the "special" $11.1 million training allocation IBEW is requesting – any allocation, and hiring practices, need to be flexible enough to respond to actual conditions such as changes in the economy and future workforce demands. It may turn out in a year or two that hiring 111 employees was not the right thing to do, leading to layoffs, and a determination that the $11.1 million investment in apprentices was not needed, even though the Company's revenue requirement would already have been increased by $11.1 million annually.[500] Rather, future hiring decisions should continue to be made by the Company's management team, looking at a wide-ranging set of data and working in concert with people like Mr. Walter, in order to make the best decisions for the Company and its customers.[501] In addition, the Company is paying for

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[497] Ex. 46, p. 13, l. 3-15.
[498] Tr. p. 973, l. 2 to p. 974, l. 3. *See, e.g.* Tr. p. 1017, l. 4 to p. 1018, l. 9, detailing examples of such technological advances.
[499] Ex. 46, p. 13, l. 16 to p. 14, l. 7.
[500] Tr. p. 994, l. 16 to p. 995, l.4; p. 1010, l. 23 to p. 1012, l. 20; p. 1002, l. 23 to p. 1003, l. 15.
[501] Tr. p. 998, l. 18 to p. 999, l. 6.

its current apprenticeship programs without any special rate case allocation, and as earlier noted is not requesting any such allocation.[502]

IBEW failed to present competent and substantial evidence that the Company is not currently providing safe and adequate service, or evidence that IBEW's recommendations are necessary in order for the Company to be able to continue to provide safe and adequate service. The Company is unwilling to accept a special allocation for internal workforce training. Under those circumstances, what is motivating IBEW to seek a Commission order requiring Ameren Missouri to bring on 111 new apprentices to be trained as employees in its distribution and transmission systems over the next three years? The motivation is clear. IBEW simply wants the Commission to somehow force the Company to "do what we've been doing for 100 years" with an *internal* workforce.[503] However, IBEW's collective bargaining agreement with the Company does not address work force numbers.[504] The facts are that the number of Ameren Missouri employees among IBEW members has been steadily dwindling,[505] and IBEW is attempting to use this rate case to try to force the creation of the proposed 111 new Ameren Missouri apprentices/employees who would then become new IBEW members.[506]

IBEW's expressed concerns and predictions about Company staffing and training, it's somewhat contradictory statements about outside contractors, and its self-interest in increasing Ameren Missouri's internal workforce and decreasing its contracted workforce, simply do not constitute evidence. Moreover, it is clear in this case that there is simply no authority for the Commission to dictate the Company's hiring practices. The Company has the right to continue

[502] Tr. p. 1015, l. 16 to p. 1016, l. 10.
[503] Tr. p. 1054, l. 7-11.
[504] Tr. p. 1034, l. 17-22.
[505] Tr. p. 1032, p. 6 to p. 1033, l. 14.
[506] Tr. p. 1022, l. 19 to p. 1023, l. 7.

to make day-to- day management decisions such as training and staffing decisions, without Commission intervention.

B. IBEW's proposal that the Commission make a special annual rate allocation for the repair and replacement of aging infrastructure should not be granted because the Company has not requested the allocation, and such allocation would likely run afoul of the statutory prohibition against basing rates on CWIP.

Although not included in the joint list of issues tendered on behalf of all the parties, IBEW proposed that the Commission "issue an additional special annual rate allocation, in an amount deemed adequate in the discretion of the Commission, which is specifically designed for the purpose of addressing capital improvement needs." [507] IBEW's witness, Michael Walter, testified that IBEW's objective was to, "bring to light" the Company's aging infrastructure and, "to obtain financing to address [it],"[508] even though he admitted at hearing that he actually didn't know if the Company had been keeping up with infrastructure needs.[509] The proposed allocation is so nebulous that it is difficult to know exactly what was intended, but it appears that IBEW is proposing that the Commission increase the Company's revenue requirement in this case by some amount that the Commission would determine, and require that the Company expend that amount solely on future capital improvements to infrastructure, and to report quarterly on the amounts so expended.[510]

There are a variety of reasons to reject IBEW's proposal, including:

- the Company has not requested the special allocation,[511]
- there was no evidence presented on the amount that should be allocated,

[507] Ex. 800, p. 9, l. 31 to p. 10, l. 3.
[508] *Id.*, p. 3, l. 1-3.
[509] Tr. p. 1052, l. 11-19.
[510] As noted earlier, there is no mechanism – absent some voluntary agreement on the Company's part – to earmark rate revenues the Company receives.
[511] Tr. p. 1024, l. 11-15.

- there was no evidence presented on what stipulations might or should be attached to the allocation,[512]

- even IBEW's witness believes that the Company will continue to invest in infrastructure regardless of whether a special allocation is made,[513] and

- IBEW's witness admitted he could only speculate, but had no data or other evidence, that absent such allocation, the Company might be unable to continue to provide safe and adequate service.

Commissioner Hall got right to the most important reason of all, when he questioned whether such an allocation would even be legal.[514] His instinct was correct, because the proposal, as best it can be understood, would violate Missouri's statutory prohibition against including CWIP in rate base, §393.135 RSMo, which prohibits electrical utilities from charging rates based on the costs of financing utility property "before it is fully operational and used for service[.]" While the Commission could reject the proposal for any of the reasons bulleted above, the Commission *must* reject the proposal to avoid violating the prohibition against CWIP in rate base.

C. The Commission should not require the additional reporting requested by IBEW because the Company is already reporting on reliability issues, because Staff can obtain any additional information from the Company upon request, and the expense associated with preparing the requested reports is not justified by any need.

IBEW proposed that the Commission require Ameren Missouri to provide the Commission, "quarterly reports reflecting the loads on equipment and wires and the optimal replacement of aged cable, wires, poles and equipment."[515] Mr. Walter admits that he does not believe that the safety and adequacy of Ameren Missouri's system would be negatively affected

[512] Tr. p. 995, l. 5-12.
[513] Tr. p. 1025, l. 4-13.
[514] Tr., p. 1003, l. 21-23. Mr. Walter admitted that IBEW's proposal regarding rebuilding Company infrastructure probably was not "feasible." Tr. p. 1036, l. 18-21.
[515] Ex. 800, p. 9, l. 25-31.

without the recommended reporting.[516] Rather, IBEW's objective is simply to get information in front of the Commission.[517]

Mr. Wakeman testified that the Company already does significant reporting to the Commission on reliability measures and infrastructure inspections,[518] which provides information that enables Staff to evaluate the safety and adequacy of the Company's system. Adding additional reports would add additional costs, but no material value.[519] Company engineers analyze loads on feeders, transformers and substations on an annual basis, but do not generate formal reports.[520] Such reports would likely not provide material value since loads on equipment will stabilize and change over time based on variables such as the economy and customer adoption of energy efficiency.[521] The proposed reports would address issues like equipment loading, but reports on equipment performance and outages, which are already being provided, actually give the best information about the performance of the Company's utility system.[522] Finally, Mr. Wakeman testified that the Company could provide Staff with any particular information regarding infrastructure or loading, upon Staff's request.[523]

Just as in the Company's 2010 rate case, IBEW has failed to present any competent and substantial evidence that the Company is failing to provide safe and adequate service.[524] It has also failed to provide any evidence that the infrastructure-related information the Company is already providing to the Commission is somehow insufficient to permit the Commission to determine if the Company is providing safe and adequate service. Nor has IBEW shown that

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[516] Tr. p. 1026, l. 2-7.
[517] Tr. p. 1035, l. 3-22.
[518] Tr. p. 1005, l. 12 to p. 1006, l. 3.
[519] *Id.*
[520] Tr. p. 1007, l. 17 to p. 1009, l. 4.
[521] *Id.*
[522] Tr. p. 1006, l. 7-25.
[523] Tr. p. 1015, l. 7-15.
[524] *Report and Order,* ER-2011-0028, p. 103, ¶8.

there is any need for the particular infrastructure reporting it is recommending to the Commission – especially where Staff can obtain information on Ameren Missouri's infrastructure without creating the expense of additional reports, by simply asking the Company for the information. Since the requested reporting is not necessary to the safety and adequacy of the Company's utility service, the Commission should decline to order the Company to provide it.

XIII. Rate Design

A. Class cost of service and revenue allocation.

Four parties performed class cost of service studies ("CCOSS") and filed testimony in support of those studies: Ameren Missouri, Staff, OPC, and MIEC. Table 1 from the rebuttal testimony of Ameren Missouri's witness William Warwick shows that, with but one exception, the production plant allocators those studies produced are qualitatively equivalent.

Table 1

Production Plant Allocators							
Party	Method	RES	SGS	LGS/SPS	LPS	LTS	Lighting
Company	A&E 4NCP	45.34%	10.67%	29.05%	7.74%	6.50%	0.70%
MPSC Staff	Base-Intermediate-Peak	45.26%	10.36%	28.94%	7.61%	7.42%	0.40%
MIEC	A&E 4NCP	45.34%	10.67%	29.05%	7.74%	6.50%	0.70%
OPC 2	A&E 4NCP	45.34%	10.67%	29.05%	7.74%	6.50%	0.69%
OPC 1	P&A 4CP	41.45%	9.98%	29.87%	9.18%	9.13%	0.36%

The sole outlier is the four coincident peak version of the peak and average method OPC used for its study.

The results of the CCOSS performed by Ameren Missouri, Staff, and MIEC also showed the Residential and Large Transmission Service ("LTS") rate classes are currently providing below average returns, the Small Primary Service ("SPS") and Lighting classes are providing close to the average returns, and the Small General Service ("SGS"), Large General Service ("LGS"), and Small Primary Service ("SPS") classes are providing above average returns.[525]

The four coincident peak version of the peak and average method is the same cost study methodology OPC used in past Ameren Missouri rate cases, and in each case where CCOSS issues were tried and decided the Commission found OPC's study methodology is inherently flawed because it double-counts the average demand of various customer classes.[526] That double-counting causes customers with higher load factors to be allocated a disproportionate and inequitable share of production plant.[527] It also causes those same customers to be allocated a disproportionate share of the non-average demand portion of production plant investment.[528] Those same infirmities continue to afflict OPC's CCOSS methodology, which is why the production plant allocation factors produced by OPC's study are out of line with the factors produced by each of the other parties' studies.

In past cases, the Commission has found Ameren Missouri's four non-coincident peak version of the Average and Excess Demand Allocation method to be a balanced and reliable methodology.[529] Ameren Missouri therefore recommends the Commission use the Company's CCOSS for revenue allocation purposes in this case as well. But because the results of Ameren Missouri's study and the studies performed by Staff and MIEC are so similar, which of those studies the Commission chooses to rely on is not of significant concern. Except for OPC's study, any of the CCOSS presented in this case will result in a fair and reasonable rate design.

Although the results of CCOSS are useful in the rate design process, a distinct, point estimate of cost of service should not entirely control the rates the Commission sets for

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[525] Ex. 7, p. 13, l. 1-6 (Davis Direct).
[526] Ex. 50, p. 5, l. 13-17 (Warwick Amended Rebuttal).
[527] *Id*. l. 7-9.
[528] *Id*. l. 9-12.
[529] *See Report and Order*, File No. ER-2010-0036, p. 87.

Company's rate classes. As Ameren Missouri witness William Davis stated in his direct testimony:

> While using the results of a given class cost of service study is an important starting point in developing class revenue targets and rate design, no one class cost of service study yields "the" perfect result since class cost of service studies are estimates. That is not to say that all class cost of service studies are equally valid; instead, it means there is a reasonable range around the point estimates produced by the Company's class cost of service study. Other factors – such as revenue stability, rate stability, effectiveness in yielding total revenue requirements, public acceptance, and value of service – can then be considered when determining class revenue requirements and designing rates. These additional considerations drove the Company's equal percentage of increase proposal.[530]

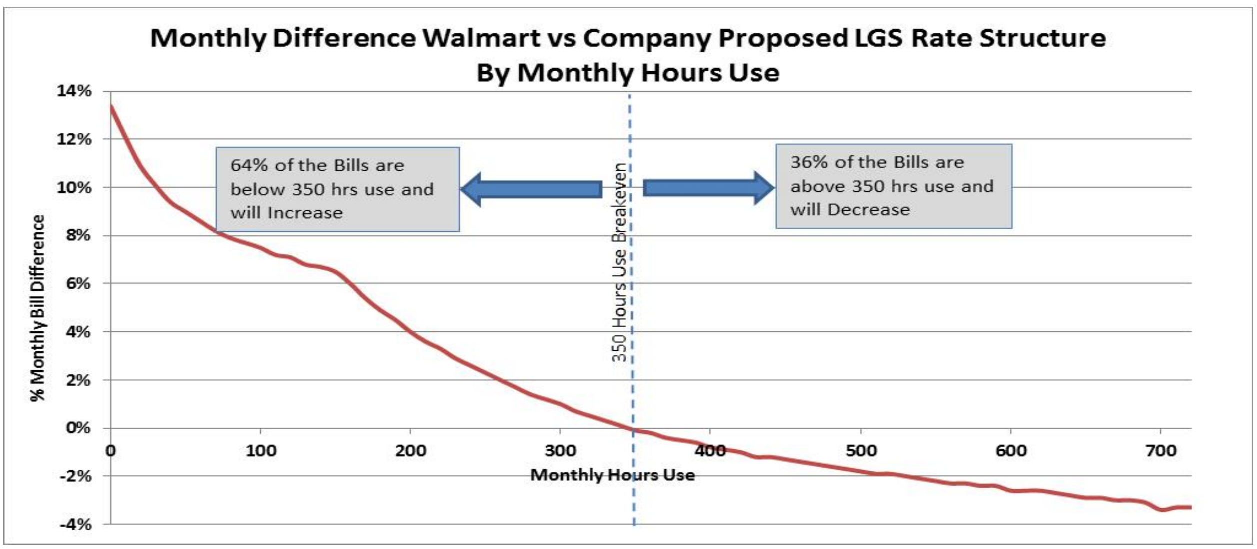
As the preceding excerpt from Mr. Davis' testimony confirms, Ameren Missouri is not proposing a rate design that includes a significant shift toward the point estimates for cost for any rate class. Instead, the Company proposes to spread a rate increase in this case across-the-board to all rate classes on an equal percentage basis.[531] However, if the Commission believes it appropriate to adjust current class cost allocations to bring them more in line with the point CCOSS results, Ameren Missouri does not oppose Staff's proposed revenue neutral shift of +0.5 percent for the Residential and LTS classes and -0.63 percent for the SGS, LGS, and SPS classes before any rate increase approved in this case is spread across all classes on a uniform percentage basis.[532]

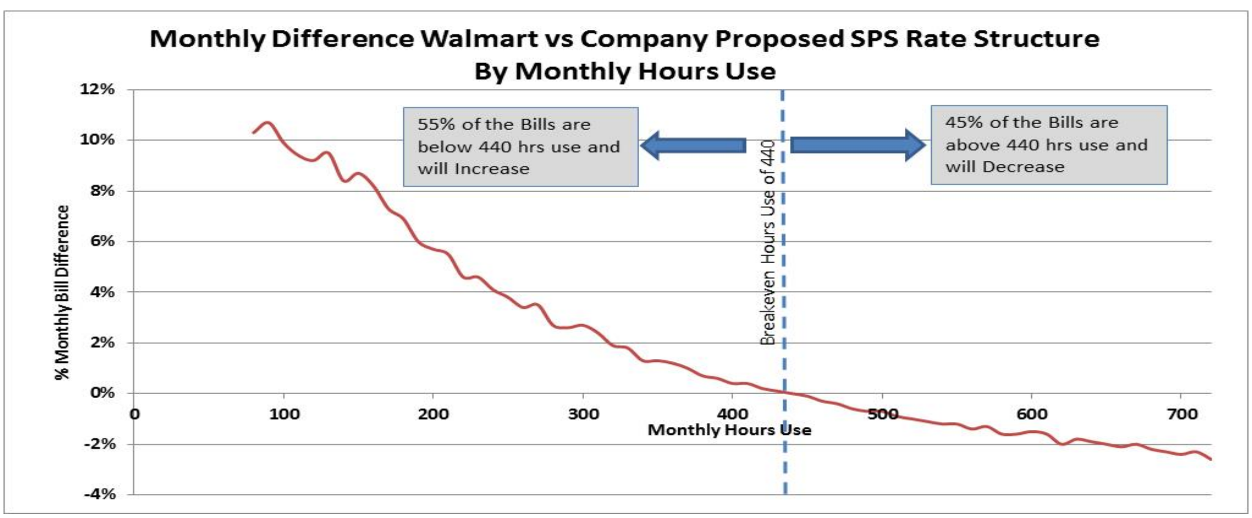
Although Ameren Missouri is amenable to Staff's proposal to move class allocations closer to the point CCOSS results, it opposes Wal-Mart's rate design proposal, which would apply half of any rate increase approved for the LGS and SPS rate classes to the initial usage block and the other half to the demand charge. Under Wal-Mart's proposal, rates for the second

[530] Ex. 7, p. 15, l. 15 to p. 16, l. 5.
[531] *Id*. p. 15, l. 8-11.
[532] Ex. 9, p. 3, l. 13-15.

and third energy blocks would remain unchanged.[533] In addition, Wal-Mart also asks the Commission to require Ameren Missouri to develop alternative rate designs for the LGS and SPS rate classes that are not based on Hours-Use rate design for the energy charge, and to present those alternatives in the Company's next general rate case.[534]

Regarding Wal-Mart's first proposal, Ameren Missouri conducted a bill impact analysis that shows the effect this proposal would have on customers in the LGS and SPS classes. The results of that analysis are shown below.[535]





[533] *Id.*, p. 6, l. 12-18.
[534] *Id.*, l. 19-22.
[535] *Id.*, p. 10, l. 1-2.

The chart shows Wal-Mart's proposal will negatively impact lower load factor customers to a greater degree than it will benefit higher load factor customers. More specifically, lower load factor customers could see double-digit percentage bill increases in addition to whatever rate increase the Commission authorizes in this case. The only customers who would benefit from this proposal would be those customers – like Wal-Mart – who can reach the third Hours-Use rate block, which in most cases means businesses who are open sixteen or more hours per day. And for most of those customers, the benefit will be limited to monthly bill reductions of only a few percentage points.[536]

Regarding Wal-Mart's second proposal, the Hours-Use rate design methodology bases rates on the size relationship between a customer's demand and the amount of energy the customer uses, and was specifically designed to deal with the diversity of loads of customers within the LGS and SPS rate classes.[537] It equitably recovers costs from customers with varying load factors, and there is no reason to believe any alternative rate design will produce results that are better or more equitable. Wal-Mart presented no evidence its proposal will produce results that are better than current Hours-Use methodology, and apparently Wal-Mart does not want to do whatever studies or analysis is necessary to develop such evidence. Instead, it asks the Commission to require Ameren Missouri to develop alternative rate designs for the LGS and SPS rate classes that are not based on Hours-Use rate design for the energy charge, and to present those alternatives in the Company's next general rate case.[538]

[536] Ex. 9, p. 9, l. 4-15.
[537] *Id*., p. 10, l. 5-8.
[538] Ex. 751, p. 17, l. 20 to p. 18, l. 2.

Ameren Missouri is satisfied the current Hour-Use rate design produces equitable rates for customers in the LGS and SPS rate classes.[539] If Wal-Mart believes otherwise, it should bear the burden of developing evidence that supports its belief. The Commission should not allow Wal-Mart to foist that burden, and its attendant costs, onto the Company.

B. Monthly residential customer charge.

Ameren Missouri proposes to increase the monthly customer charge for the Residential rate class, but instead of a specific increase – which the Company proposed in its last rate case – the customer charge would increase by the same across-the-board uniform percentage as all other rates. Ameren Missouri originally estimated that increase would move the monthly customer charge from $8.00 to approximately $8.77, but using the Company's revised rate increase request (after accounting for the true-up and settled items), the Company's current estimate is the customer charge will not likely increase to more than $8.50.

As the Commission is aware, the costs Ameren Missouri incurs to provide service to customers are generally classified as either customer, demand or energy-related. Those costs are further divided into two general categories: fixed and variable. Fixed costs are those that are not usage sensitive, while variable costs vary with the amount of electricity sold.

Generally speaking, for customer classes whose demand is not metered, the monthly customer charge is designed to reflect certain fixed charges – *e.g.*, billing, postage, and meter reading – the Company incurs regardless of whether customers use any energy, while volumetric charges – the price customers pay for each kWH of energy – are designed to reflect all remaining costs, including variable or energy-related costs. Although those are the objectives, a large portion of the fixed costs Ameren Missouri incurs to provide electric service are still reflected in its volumetric rates. This discrepancy is particularly pronounced for the Residential rate class,

[539] Ex. 9, p. 10, l. 5-8.

where about eighty percent of costs are fixed, but only about ten percent of those costs are reflected in the customer charge. That is one reason the current customer charge is only $8.00 while the Company's CCOSS supports a customer charge in excess of $20.00.

Ameren Missouri's Residential customer charge is the lowest of all Missouri investor-owned electric utilities, and is only about a third of the average monthly customer charge of all of Missouri's electric cooperatives. As shown on Table 3 of Mr. Davis's rebuttal testimony, Kansas City Power & Light has the next lowest customer charge among investor-owned utilities, and its charge is $9.00 per month.[540] And a recent survey of Missouri's electric cooperatives shows their average monthly residential customer charge is $23.70, with a minimum of $14 and a maximum of $38. In fact, sixty percent of the cooperatives surveyed have a monthly customer charge of $25 or greater.[541]

Ameren Missouri has proposed to increase the Residential customer charge in each of its last five rate cases, but only one of those increases was approved. That means the gap between fixed costs the customer charge was meant to cover and the costs it actually covers has continued to grow. Over the course of those five rate cases, for every five percent increase in volumetric charges there has been only a one percent increase in the monthly customer charge. And although a uniform percentage increase in the Residential customer charge in this case will not improve that ratio, it will prevent the ratio from eroding even further.

Staff, OPC, and CCM oppose any increase in the residential customer charge. Staff's opposition is based on "policy guidance" from the Commission's *Report & Order* in Ameren Missouri's last rate case. In that order, the Commission concluded Ameren Missouri's monthly customer charge should not be increased for public policy reasons. More specifically, the

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[540] Ex. 9, p. 16, l. 1-2.
[541] *Id.*, l. 7-11.

Commission found shifting costs from volumetric rates to the monthly customer charge would tend to reduce a customer's incentive to save electricity because increases in volumetric rates would adversely affect the payback periods associated with energy efficiency measures.[542]

But that finding ignores at least three critical facts. First, whatever the record in Ameren Missouri's last rate case may have shown, there is no evidence in this case that increasing the Residential customer charge will reduce customers' incentive to save electricity by implementing energy efficiency measures. Second, the Commission's finding ignores the fact the final order in this case will increase Ameren Missouri's volumetric rates. In light of that increase, a minimal increase to the monthly customer charge should not be enough to dissuade customers who are considering adopting energy efficiency measures from doing so, because adopting such measures will enable them to mitigate the impacts of increased volumetric charges. Moreover, it is unreasonable to assume the meager increase in the customer charge Ameren Missouri seeks – which likely will total less than $6.00 over the course of an entire year – will have ***any*** impact on customers' energy efficiency decisions. But even if it were reasonable, assumptions are not competent and substantial evidence.

The final critical fact the Commission's finding ignored is that artificially inflating volumetric charges sends inaccurate price signals to customers regarding the savings potential of energy efficiency measures. Higher volumetric charges will certainly make energy efficiency measures appear to be more attractive and cost-effective, and also will shorten the payback period on any measures customers decide to adopt. But if those were the true objectives of energy efficiency measures, why not do away with the customer charge altogether, thereby making the measures appear to be even more attractive and shortening the payback period even more? The answer is simple: creating false premises to encourage and attempt to justify

[542] *Report and Order*, File No. ER-2012-0166, pp. 110-111.

adoption of energy efficiency measures is not the true objective. As the Missouri Energy Efficiency Act[543] makes clear, although it is state policy to encourage energy efficiency through adoption of demand-side measures, that policy is premised on the requirement that measures adopted to achieve that objective are cost-effective. And because real cost-effectiveness can only be determined by comparing potential savings that can be achieved through demand-side measures to the cost of supply-side alternatives, artificially inflating volumetric charges – which represent the supply side – will make it impossible for customers to determine if energy efficiency measures they adopt are truly cost-effective.

In addition, the Commission must be careful not to tilt rate design for the Residential class too much in favor for energy efficiency, because many of the Company's customers who have above average energy usage are low-income customers with little or no opportunity to adopt energy efficiency measures to reduce their monthly energy consumption. Other customers who are not low-income – such as those who rely on electricity for space heating – also have few opportunities to reduce their consumption by adopting low-cost energy efficiency measures. Artificially inflating volumetric rates to ostensibly promote energy efficiency would actually be detrimental to customers in those groups.

The problems created by these artificially low customer charges will not go away, but instead will only get worse. Consider, for example, that solar rebates are only available to those that can afford to install solar panels, but as solar usage increases, volumetric charges increase, which also tends to disadvantage lower income customers who may not be able to afford solar panels.

[543] §393.1075, RSMo.

The Commission also should recognize that if the Company's request to increase the Residential customer charge is again denied half of customers in that rate class would receive, as they have in past rate cases, above average rate increases.

C. Economic development.

In its October 20, 2014 *Order Directing Consideration of Certain Rate Design Question*, the Commission invited parties to submit testimony addressing questions regarding whether rate design mechanisms should be established to promote stability or growth of customer levels in geographic locations where there is underutilization of existing infrastructure. Although several parties submitted testimony on this issue, no party's testimony included a specific proposal for a tariff implementing any such rate design mechanisms. Instead, those testimonies discussed general concepts regarding economic development rates and provided comments on a range of issues and proposals – some general, some specific – the Commission should consider if it decides to expand such rates in the future.

In supplemental direct testimony filed in response to the Commission's order, Ameren Missouri witness William Davis described the Economic Re-Development Rider ("ERR") that has been part of the Company's tariff since 2007. Mr. Davis explained "[t]he purpose of the company's ERR tariff is to encourage re-development of certain sites in the City of St. Louis and, more specifically, to encourage the utilization of existing distribution facilities with capacity in excess of current load in those areas."[544] Customers in the LGS, SPS, and LPS rate classes are eligible to apply for service under this tariff, and those who qualify receive a discount that reduces the cost of their electric service.[545] In order to qualify for the ERR, customers must satisfy several criteria specified in the tariff. In addition to being in one of the eligible rate

[544] Ex. 8, p. 2, l. 4-6 (Davis Supplemental Direct).
[545] *Id.*, l. 7-18.

classes, a customer must: (1) be located within designated areas in the City of St. Louis; (2) be receiving some type of local, regional, or state government economic development assistance; (3) have a projected annual load factor estimated to equal or exceed fifty-five percent; (4) have a projected monthly peak demand of at least 500 kilowatts; and (5) be located where existing infrastructure can be utilized in a manner that is beneficial to the local electric delivery system.[546] Under the ERR, the maximum discount available to qualifying customers is fifteen percent, and no customer can receive the discount for more than five years.[547]

Staff's *Rate Design and Class Cost-of-Service Report*, which was filed at the same time as Mr. Davis's testimony, more comprehensively addressed the questions regarding economic development rate mechanisms that were included in the Commission's October 20, 2014 order. In its report, Staff identified and described numerous issues that would need to be considered in designing and implementing such rate mechanisms. Staff also stated much more information than is currently available would need to be gathered and considered to determine whether such mechanisms are feasible or desirable and, if so, how they should be structured, implemented, and administered. This led Staff to conclude formation of a collaborative that affords all stakeholders interested in economic development rate mechanisms would provide the best opportunity to fully explore and estimate the potential benefits of such mechanisms and what features they should be include.[548]

Ameren Missouri supports Staff's proposal to form a collaborative. As Mr. Davis pointed out in his rebuttal testimony, one advantage of a collaborative is it could include all regulated utilities from all regions of Missouri, who could discuss and share best practices based

[546] *Id*. p. 3, l. 10 to p. 4, l. 14.
[547] *Id*. p. 4, l. 16-17.
[548] Ex. 201, p. 45, l. 18-20.

on their individual experiences.[549] Another advantage is the universe of potential non-utility participants would be expanded beyond the list of parties to this rate case. Mr. Davis further described the benefits a collaborative would provide, and identified some of the issues such a group should consider:

> First, each of the specific questions asked by the Commission can be further investigated to the extent necessary. In addition, the MDOE provided testimony asking the Commission to require recipients of economic development benefits to also participate in energy efficiency programs. While the Company is not opposed to the concept, there are issues related to that proposal that need to be explored. For example, energy efficiency programs are approved in three-year increments, while the MDOE's proposal would require participants to implement all projects within the contract term period, which could be as long as five years. My concern with this type of timing difference is that cost recovery of program incentives is linked to the three-year implementation plan, and the Company may not be able to pay out rebates for projects implemented outside the three-year implementation window. I also am concerned the programs may change between implementation periods, which would catch customers with five-year contracts straddling two program periods.
>
> The MDOE also requests the Commission to approve an exemption related to Section 393.1124.14, RSMo, (customers receiving certain state tax credits cannot also participate in energy efficiency programs). I am not a lawyer, but I do not think the Commission can waive a statutory requirement. But if a collaborative found this issue to be of sufficient value, then it is possible a broadly-supported proposal for a legislative change could be made.
>
> A final example of why a collaborative would be beneficial is OPC's testimony about applying an economic development discount to entire geographic regions. While the idea seems intriguing on its face, more research to properly identify candidate areas and to determine whether temporary discounts on electric rates are motivation enough to encourage residential customers and/or smaller businesses to move to a particular area to the degree that the electric system's utilization would improve materially. Contrasting the load characteristics of residential customers and smaller businesses to higher load factor customers that currently qualify for economic development discounts would be another important research topic, assuming the goal is to support a more efficient utilization of existing resources.[550]

[549] Ex. 9, p. 36, l. 1-5.
[550] *Id.*, p. 36, l. 8 to p. 37, l. 13.

There simply are too many unanswered questions about whether it is necessary or desirable to revise or expand Ameren Missouri's current ERR and, if so, what a revised or expanded economic development rate mechanism would look like. Those questions cannot be resolved based on the record in this case, because competent and substantial evidence does not exist to warrant or support such changes. If the Commission wants to pursue this issue, it should do so in the manner Staff proposes, because only through a collaborative will interested parties have the opportunity to identify and fully consider all relevant issues.

PART TWO: NORANDA'S SUBSIDY PROPOSAL

I. LEGAL AND POLICY CONSIDERATIONS

Noranda Aluminum, Inc. ("Noranda") asks the Commission to do something that it has never done before; that is, set a rate based solely upon a customer's claim of what it can afford to pay. There is a very good reason why the Commission has never taken such action, because approval of such a proposal would constitute unlawful, undue discrimination, yet Noranda invites the Commission to approve unlawful and unduly discriminatory rates. This Commission long ago recognized (a recognition cited and quoted with approval by the Missouri Supreme Court) that the Public Service Commission Law ("PSC Law") "and judicial decision forbids any difference in charge which is not based upon difference of service and even when based upon difference of service [the difference] must have some reasonable relation to the amount of the difference, and cannot be so great as to produce unjust discrimination."[551]

[551] ***State ex rel. The Laundry, Inc. et al. v. Pub. Serv. Comm'n**,* 34 S.W.2d 37, 44-45 (Mo. 1931), *citing Civic League of St. Louis et al v. City of St. Louis,* 4 Mo. P.S.C. 412.1. *See also* **Western Union Telegraph Co. v. Call Pub. Co.**, 181 U.S. 92, 100 (1901), *quoted with approval* by our Supreme Court in ***The Laundry, Inc.*** at 34 S.W.2d at 45 (The principle of equality that calls for all to have equal service and charges does not forbid different charges for different service, but it "does forbid any difference in charge which is not based upon difference of service.").

The factors that Noranda points to as justification for a large subsidy from other customers have nothing to do with differences in the *service* Ameren Missouri provides to Noranda versus the service provided to other customers. To the contrary, the factors relied upon by Noranda are solely based on Noranda's claims about the particular characteristics of Noranda's private business **–** *e.g.*, the aluminum prices it can receive for its products, its relative cost position in producing its products vis-à-vis competitors, how much cash and liquidity it has, and what capital investment it needs or may need to make. None of those factors has any bearing whatsoever on how Ameren Missouri serves Noranda or at what cost. Consequently, Noranda's request cannot be approved as a matter of law.

This Commission has recognized that it cannot set rates that are unduly or unreasonably discriminatory, as evidenced by its Report and Order from last summer. The Commission noted "…Complainants must shoulder a very heavy burden to show that such a rate would not be unduly or unreasonably preferential."[552]

The Commission's focus on setting cost of service rates is not new. The Commission has previously made a finding of undue discrimination in the *Civic League* case. In that case, the City of St. Louis (whose rates were subject to Commission jurisdiction at the time) sought to give "manufacturers" a special rate to encourage them to locate in the City.[553] In other words, the City was trying to give advantageous rates to certain businesses that had particular characteristics unrelated to how the utility would serve them in order to promote economic development in the City. The court found this to be unlawful, but it mirrors what Noranda asks this Commission to do here. Just like the manufacturers in *Civic League*, Noranda wants an advantageous, subsidized rate justified solely by its own business characteristics, which have

[552] *Report and Order*, File No. EC-2014-0224, p. 23, ¶K.
[553] ***The Laundry, Inc.***, 34 S.W.2d at 44.

nothing to do with how Ameren Missouri serves Noranda (or at what cost). Instead, in addition to its claim that a subsidized rate is necessary for it to stay in business, Noranda supports its claims by citing the jobs it will keep or create, the taxes it will pay, and the economic activity it creates and maintains. Promoting these economic benefits may indeed be laudable – just as they may have been laudable for the City of St. Louis in *Civic League* – but this Commission has not been empowered to sanction the undue discrimination that would be required to promote these economic benefits through creating a subsidized power rate for Noranda. Simply stated, this Commission lacks the statutory authority to do what Noranda asks. Could the General Assembly confer such authority on the Commission? The answer is likely "yes." But has it done so? This Commission long ago recognized in *Civic League* that the answer is "no."

In different circumstances, Ameren Missouri would not be alone in its contention that what is being asked of the Commission here is unlawful. On September 12, 2012, the Missouri Industrial Energy Consumers ("MIEC"), represented by the same lawyers who represent Noranda in this case, filed Comments in the Commission's then-pending *Working Case to Consider the Establishment of a Low-Income Customer Class or Other Means to Help Make Electric Utility Services Affordable*.[554] In those Comments, MIEC, citing precisely the authority we cite above, stated as follows: The Missouri Supreme Court long ago concluded that differences in rates must be based upon differences in service.[555] The citation, by the way, is to the ***The Laundry*** case, using it in exactly the same manner Ameren Missouri cites it in this case. There, a large commercial laundry operation that used over 500,000 gallons of water a month sought to be included under a rate class for manufacturers who consumed over 500,000 gallons

[554] File No. EW-2013-0045, quoted in Ex. 9, p. 29, l. 21 to p. 30, l. 20. The entire MEIC filing is attached as Schedule WRD-R5.
[555] In ***State ex Rel. The Laundry, Inc. and Overland Laundry Company v. Pub. Serv. Comm'n***, 34 S.W.2d 37 (Mo. 1931), the Supreme Court addressed the appropriate standard under what is now subsections 393.130.2 and 3.

of water each month. The evidence showed that the manufacturers' rate was below the water company's cost of service and that the water company adopted the special rate for the purpose of luring manufacturers to the water company's service territory in order to serve the manufacturer's employees that would presumably locate there as well. The court cited section 393.130's predecessor statute and a Commission decision in concluding that the discrimination against the laundry company compared to other large users of water and employers was illegal because it was not "bottomed upon any dissimilarity or difference in service or operative conditions[.]"[556]

Even given the findings of *The Laundry* case, there could be circumstances where a departure from strict cost-of-service ratemaking does not present a case of clear undue discrimination (*e.g.*, where various class cost of service studies produce a range of cost results, as would be typical in a general rate case), but this is not that case. And no party to this case is even arguing that Noranda's request has any basis whatsoever in any difference in the nature or character of the service Ameren Missouri provides Noranda. Based upon the foregoing, the Commission's inquiry in this case should end here, and the relief sought should be denied.

Setting aside for the moment the legal impediments to Noranda's proposal, abandoning the principle of cost-based rates for all of Ameren Missouri's customers represents bad regulatory policy that cannot be justified based on the evidence in this case. Noranda's request for a rate subsidy is contrary to all of these generally accepted principles of utility ratemaking. Once the Commission accepts this as a valid basis for setting rates, how will it respond to similar requests for other large electricity customers? Or requests from charitable organizations? Or the Mom-and-Pop corner store? Any customer, commercial or residential, could face financial difficulty which would be eased if only the electric bill were reduced.

[556] *Id.* at 45.

Noranda's request is also bad policy because it is unfair to require Ameren Missouri's customers to bear the entire burden of subsidizing the New Madrid smelter, if a subsidy is appropriate at all. Mr. Davis testified that approximately 47 percent of the households in Missouri's Bootheel region – the area where the smelter is located and whose residents most directly benefit from its continued operation – are not Ameren Missouri customers and will not pay one penny more in rates to provide Noranda the subsidy it seeks in this case.[557] Instead, the entire burden of the proposed rate subsidy will be borne by Ameren Missouri's other customers, approximately 97 percent of whom do not live in the Bootheel area.[558] Mr. Davis further testified that the majority of the Company's customers are in the St. Louis metropolitan area, more than 150 miles from the smelter. Beyond the St. Louis area, Ameren Missouri's service area extends northwest past the City of Excelsior Springs.[559] Any benefits these customers derive from the New Madrid smelter would be both remote and indirect, yet under Noranda's proposal they will be forced to directly subsidize the smelter's operations while almost half the households in the Bootheel region will provide no subsidy whatsoever.

As noted earlier, the Commission lacks the legal authority necessary to grant Noranda the rate subsidy it seeks in this case, and unless and until the elected members of the General Assembly pass legislation that gives the Commission the ability to set electric rates based on a customer's individual economic or financial circumstances, the rate subsidy Noranda seeks cannot be granted even if the Commission believes such action is warranted by the evidence in this case. But beyond these legal considerations, the issues raised by Noranda's complaint are not questions of *public utility regulation*; instead, they are questions of *public and legislative policy*. Only the General Assembly can consider and resolve the broad public policy questions

[557] Ex. 9, p. 27, l. 12 to p. 28, l. 12.
[558] *Id.*, p. 26, l. 21 to p. 27, l. 5.
[559] *Id.*, p. 28, l. 6-12.

raised by Noranda's request, including (1) whether public support for Noranda is necessary and appropriate, and (2) whether the burden of subsidizing Noranda should be borne by the customers of a single utility or should, instead, be borne by all Missourians.

Aside and apart from the fact that Missouri's General Assembly ***must*** act before the Commission can grant Noranda's request for a special rate, questions related to whether Noranda needs or deserves public support to continue operating are the types of issues the General Assembly ***should*** decide. If, as Noranda argues, closing the smelter will negatively affect the economy statewide, then a statewide remedy should be fashioned. And the General Assembly is the only governmental entity that can provide relief that is not specifically limited to Ameren Missouri's customers. The Commission recognized and relied upon this fact when it denied Noranda's requested relief in the complaint case last summer. "Finally, and importantly, a request for an economic development subsidy of this magnitude is more properly directed to the Missouri General Assembly."[560]

Finally, it should be noted that the Commission is not designed by statute to regulate any entities other than utilities. The Commission's authority under the PSC Law is limited to that necessary to compel *public utilities* to produce information necessary to enable the Commission to perform its regulatory duties, including allowing the Staff to conduct audits and investigations of utilities' operations, and allowing the Commission to enforce its orders in Missouri's courts. Those statutes confer no similar authority with regard to Noranda or any of the Company's other customers who may be induced to seek special rates in the future.

Additionally, neither the Commissioners nor its Staff have the authority or the expertise necessary to fully evaluate and rule upon any individual customer's claims of financial need. This case and the complaint case heard last summer are illustrations of that point. Staff did not

[560] *Report and Order*, File No. EC-2014-0224, p. 28.

evaluate the validity of Noranda's claim of financial distress. In fact, not one party, other than Ameren Missouri, offered any investigation into the validity of Noranda's financial claims. Not in this case and not in the rate design complaint case filed last year. The Commission's (and its Staff's) expertise is in the areas of public utility regulatory law and policy and the operations of public utilities subject to its jurisdiction. That expertise does not extend to other industries, in general, or, more specifically, to the finances and operations of Ameren Missouri's individual customers. If the Commission crosses this extremely significant regulatory Rubicon and takes the unprecedented step of granting rate relief to Noranda, the difficulties it has faced in this case will be greatly magnified in the future when Ameren Missouri's other customers – either commercial or residential – inevitably seize upon a ruling in favor of Noranda as grounds to request their own special utility rates. Each such request would require the Commission to conduct the same type of investigation that it has been asked to conduct for Noranda, even though it lacks the experience, expertise, or resources to do so. The potential administrative burdens this could impose would be enormous and would divert the Commission's already limited resources away from the regulatory objectives and responsibilities conferred on it by the PSC Law.

Finally, as discussed in the Introduction to Part One of this brief, much effort is put into trying to keep the cost of electric service as affordable as possible. However, if customers are burdened with paying costs for what should be Noranda's retail rate, then every dollar that is transferred from our low-income customers undercuts the efforts that have been undertaken.

II. LACK OF PROOF OF FINANCIAL NEED

Even if Noranda's request for relief was lawful, and did not reflect bad regulatory policy, the factual record does not support Noranda's request. More specifically: (1) the only forecast of actual future aluminum prices that is in evidence indicates that, even with Noranda's own capital expenditure assumptions, no liquidity crisis will occur (and Noranda's capital expenditure assumptions are likely inflated[561]); (2) Noranda's story of a possible liquidity crisis relies upon unsupportable economic assumption and the illogical contention that Noranda would do nothing to avoid an impending crisis; and (3) even if a liquidity crisis were to occur, Noranda's own admissions and conduct indicate that smelter closure is neither the only, nor even the most likely, Noranda response. In short, it appears that Noranda has again inflated both the alleged danger and the purported severity of the response in order to obtain shareholder value-enhancing electric rates. Noranda's cry of "WOLF!" is all the more obvious when one compares what Noranda tells Wall Street and the public with the "Highly Confidential" story it tells this Commission.

A. Future forecasts of aluminum prices do not support Noranda's story.

While there is much on which the various witnesses disagreed, Noranda and Ameren Missouri agree on one thing: in this case, the definitive expert forecast of future aluminum prices is the forecast provided by CRU.[562] As admitted by Noranda CFO Dale Boyles, CRU's forecast is the "best prediction [he] is aware of."[563] CRU's forecast represents the estimate of the most likely future price.[564] This forecast results from the cumulative analysis by a team of industry experts of the many factors that together influence future aluminum prices.[565] Noranda

[561] As discussed, infra, these alleged future capital expenditures substantially exceed historical spending patterns and are, at best, poorly documented.
[562] Tr. p. 2501, l. 11 to p. 2053, l. 16; Tr. p. 2526, l. 7-10; Tr. p. 2528, l. 21 to p. 2529, l. 2; Tr. p. 2188, l. 14 to p. 2189, l. 9; Tr. p. 2192, l. 25 to p. 2193, l. 4; Tr. p. 2196, l. 21 to p. 2197, l. 8; Tr. p. 2202, l. 7 to p. 2203, l. 11; Ex. 19, p. 4, l. 1-2 (Humphreys Rebuttal); Ex. 33, p. 20, l. 13-18 (Mudge Rebuttal).
[563] Tr. p. 2528, l. 21 to p. 2529, l. 2.
[564] Tr. p. 2190, l. 1-12.
[565] *Id.*; Tr. p. 2537, l. 16-22.

has, in the past, relied on CRU's forecast in presentations to third parties.[566] There is, in fact, no other forecast of future aluminum prices in evidence in this case.[567]

Using this best – and in fact only – expert evidence of future aluminum prices, and otherwise leaving Noranda's other assumptions unchanged, indisputably reveals that Noranda will likely achieve liquidity well in excess of (and generally more than double) Noranda's arbitrary **[redacted]** threshold.[568] As explained in his filed testimony, Ameren Missouri witness Robert Mudge took CRU's forecast aluminum prices (instead of Mr. Boyles' significantly lower, "what-if" aluminum prices) and put them into *Noranda's* model.[569] He otherwise used the model exactly as Mr. Boyles used it, and used Mr. Boyles' other assumptions.[570] Mr. Mudge then calculated the liquidity levels Noranda would achieve using this best-available price forecast, and determined that Noranda would never come close to its hypothetical **[redacted]** red line:[571]

**

[redacted]

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Noranda doesn't challenge Mr. Mudge's numbers because it can't. Noranda could not, and does not, challenge CRU's authoritative forecast upon which Mr. Mudge relied. The remainder of Mr. Mudge's assumed numbers come straight from Noranda. Mr. Mudge runs those numbers through the same Noranda "enterprise model" that Mr. Boyles used. In short, it

[566] *Report and Order,* File No. EC-2014.0224, at Finding of Fact #16.
[567] Tr. p. 2189, l. 10-21. As discussed *infra*, the "scenarios" developed by Mr. Boyles are emphatically *not* forecasts.
[568] As admitted by Mr. Boyles, Noranda's **[redacted]** liquidity "critical point" is not a calculated figure, but rather what Noranda's executives "believe" Noranda's minimum liquidity to be." Tr. p. 2557, l. 10 to p. 2558, l. 4. It is, as Mr. Boyles admitted, "a feeling." *Id.* at 2558, l. 2-4.
[569] Ex. 33, p. 17, l. 1-7.
[570] *Id.*
[571] Ex. 33, Table 3.

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is undisputed that if one uses CRU's expert forecast of future prices (and the only price forecast in evidence in this case), then Noranda will never come close to a liquidity crisis.

B. Noranda's "scenarios" are fundamentally flawed.

Because Noranda cannot dispute Mr. Mudge's numbers, it attempts to focus this Commission on alternative "what-if" scenarios. But, the testimony reveals that these scenarios are, at best, methodologically unsound and created specifically to support Noranda's attempt to manufacture a liquidity crisis for presentation in this case (as it did in File No. EC-2014-0224) where none exists.

Noranda admits that its scenarios are *not* forecasts. Mr. Boyles, the scenarios' creator, states this:

> **Q. And you're not presenting these [scenarios] to the Commission as forecasts, correct?**
> A: That's correct.[572]

Noranda witness Colin Pratt agrees: "The first point is that the three scenarios need to be seen as exactly that – i.e. as scenarios and not forecasts."[573] Noranda witness Steven Schwartz likewise acknowledges this distinction.[574] Even Noranda is not suggesting that these scenarios are offered to show the Commission a forecast path for Noranda's future.

Rather, these scenarios are merely a "what-if" hypothetical. Mr. Boyles explicitly admits this:

> **Q. [These scenarios are] basically a what if, fair?**
> A. That's fair. [575]

[572] Tr. p. 2521, l. 3-12.
[573] Ex. 609, p. 6, l. 16-17 (Pratt Surrebuttal).
[574] Tr. p. 2895, l, 25 to p. 2896, l. 7.
[575] Tr. p. 2521, l. 3-21.

At a certain level, Ameren Missouri does not disagree with Noranda. Noranda can make up whatever future aluminum price numbers it chooses. But, those numbers are made-up, and are not forecasts. Moreover, the methodology behind those numbers is fatally flawed.

i. <u>Mr. Boyles' fundamental assumption of a ten-year aluminum price cycle is arbitrary and unsupported</u>**.**

Mr. Boyles commenced his what-if analysis by *assuming* that aluminum prices follow a ten-year cycle.[576] Mr. Boyles' basis for this assumption is illusory at best. He has no particular training in either the aluminum industry or aluminum price cycles, and has only been employed in the aluminum industry for a little over a year.[577] As he admits, the aluminum industry is "fairly new" to him.[578] He did not perform any statistical analysis to test his hypothesized ten-year cycle.[579] He cites to no economics texts or peer-reviewed publications in support. He simply assumed.

This assumption, however, has a critical bearing on his conclusions. As Dr. Humphreys explained, inherent in any "cycle" is a "mean" or "average" line, with actual prices "cycling" above and below this line.[580] Mr. Boyles agrees.[581] This truth can be seen in Mr. Boyles' scenarios, which show prices below and above an average price of ****[redacted]**** per pound:

[576] Tr. p. 2505, l. 25 to p. 2506, l. 8.
[577] Tr. p. 2495, l. 7 to p. 2497, l. 2.
[578] Tr. p. 2498, l. 1-3.
[579] Tr. p. 2505, l. 6-14.
[580] Tr. p. 2209, l. 10-19.
[581] Tr. p. 2506, l. 17 to p. 2507, l. 17.

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[redacted]

**[582]

Thus, if Mr. Boyles had chosen a five-year cycle, then he would have been required to assume both low and high prices occurring during that five-year period.[583] The only way that Mr. Boyles could achieve a long run of hypothetical low prices for six or seven years was to assume a ten-year cycle.[584]

Both Noranda and Ameren Missouri experts criticize this assumption. Dr. Humphreys testified that one could not predict a particular length or pattern of aluminum price cycles.[585] Mr. Pratt agreed: "I believe Dr. Humphreys and I agree that the timing of these cycles cannot be

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582 Ex. 19 p. 5, Figure 1 (Humphreys Rebuttal).
583 Tr. p. 2208, l. 19 to p. 2209, l. 25; Tr. p. 2506, l. 17 to p. 2507, l. 17.
584 Tr. p. 2208, l. 19 to p. 2209, l. 25. *See also* Tr. p. 2210, l. 18 to p. 2211, l. 4.
585 Tr. p. 2193, l. 5-19; Tr. p. 2192, l. 6-24; Tr. p. 2201, l. 5 to p. 2202, l. 2.

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predicted with any accuracy."[586] According to Dr. Humphreys, these assumed ten-year cycles are "arbitrary" and lack any "scientific basis."[587] Mr. Pratt went on to further confirm Dr. Humphreys' criticism of Mr. Boyles' assumptions:

> **Q: Do you and Dr. Humphreys agree on the ability to forecast the timing of future price cycles for aluminum?**
> A: I believe we do.
>
> **Q: In what way do you agree?**
> A: In that we have very little ability to predict cyclical timing beyond the short term (1-2 years) and even in the short term there is potential for significant errors and unforeseen events.[588]

Even Mr. Boyles must ultimately admit that the "peaks" and "troughs" he purports to calculate cannot, in fact, be predicted:

> **Q. And so you saw in that surrebuttal where Mr. Pratt said you can't predict peaks and troughs in a cycle. You saw that, correct?**
> A. Yes.
>
> **Q. Peaks being things like this little blue line [referring to Humphrey's Figure 1]that goes up and troughs being the one right here that goes down, those are peaks and troughs, correct?**
> A. That's correct.[589]

Little wonder, then, that Mr. Pratt testified that purporting to predict the timing of price cycles "could be very misleading,"[590] an opinion shared by Dr. Humphreys.[591]

In fact, review of historical aluminum prices reveals no support for a consistent ten-year cycle; if anything, aluminum prices, measured "peak-to-peak" and "trough-to-trough," cycle more quickly than ten years.[592] Thus, aluminum industry economists from both sides agree: Mr. Boyles cannot validly assume a ten-year price cycle. Mr. Boyles' analysis, however, is fundamentally grounded upon this baseless assumption.

[586] Ex. 609, p. 2, l. 12-13.
[587] Tr. p. 2192, l. 6-24.
[588] Ex. 609, p. 5, l. 18 to p. 6, l. 4.
[589] Tr. p. 2517, l. 3-11.
[590] Ex. 608, p. 11, l. 23-25 (Pratt Direct).
[591] Tr. p. 2201, l. 6 to p. 2202, l. 19.
[592] Tr. p. 2208, l. 7-17.

ii. Mr. Boyles scenarios are not realistic representations of hypothetical possibilities.

The flaws in Mr. Boyles' model are not limited to improperly assuming a particular cycle length. The three scenarios that Mr. Boyles featured in his testimony all conveniently assume a long run of low prices (six to seven years) which allow Mr. Boyles to hypothesize ever-worsening liquidity. Dr. Humphreys criticized this approach,[593] and Mr. Pratt agreed:

> Dr. Humphreys's main point is that the three scenarios selected by Noranda are not sufficiently representative of potential price cycles, because they all contain a long sequence of negative variations from trend in the first few years of the forecast. I believe this is a valid point and that a broader range of samples should be selected.[594]

The central point of Mr. Boyles assumption – year after year of inordinately low prices – not only contradicts the authoritative forecast for those years, but is not even a reasonable hypothesis.

iii. Mr. Boyles possesses no colorable justification for creating, let alone focusing on, the three most negative scenarios.

Finally, the entire justification for Mr. Boyles' scenario lacks support. According to Mr. Boyles, he undertook this analysis because CRU's forecast did not reflect price volatility, and he selected three featured scenarios in order to reflect an alleged market condition where prices were predicted to decline. Both of these purported justifications do not stand up to scrutiny.

CRU's forecast includes implicit volatility. Mr. Pratt and Dr. Humphreys agree on this point.[595] According to Mr. Pratt: "The CRU forecast is a mean expected price, including implicit volatility as Dr. Humphreys says."[596]

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593 Ex. 19, p. 9. l. 4-8; Tr. p. 2207, l. 4 to p. 2208, l. 24.
594 Ex. 609, p. 6, l. 8-12.
595 Ex. 19, p. 7, l. 2-9; Ex. 609, p. 3, l. 1-2.
596 Ex. 609, p. 3, l. 1-2.

Likewise, CRU's forecast already includes analysis of market factors, including factors which might have either a downward or upward effect on pricing. According to Mr. Pratt, CRU's forecast for the next one to five years uses a "market model of demand and supply" that forecasts "inventory and price movements."[597] CRU's analysis includes macro-economic forecasts of world economies, aluminum capacity under construction, supplier production decisions, inventory levels, spot pricing in relation to trends, interest rates, and economic growth trends.[598] Dr. Humphreys noted that CRU has a global network of offices collecting and assembling relevant data, including likely demand levels, production expectations, smelter outputs and other market information.[599] CRU's comprehensive analysis models "the fundamentals of supply and demand," and reflects "variations in economic growth, metal output and inventory levels…."[600]

There is simply no evidence that CRU's forecast is overly optimistic or does not take into account CRU's (and by extension, Mr. Pratt's) views on the expected future path of aluminum prices. Despite this, Mr. Boyles hypothesizes a long series of negative prices from 2016 through at least 2023.[601] According to his testimony, Mr. Boyles makes this hypothesis based on a statement he attributes to Mr. Pratt:

> We based our determination of which of the 11 scenarios was most representative of the future on an evaluation of current market conditions summarized on page 11 of Mr. Pratt's December 19, 2014 direct testimony: "An implication of these starting conditions is that it is unlikely that the aluminum market will experience tight market conditions in the next two years." (Note that the word "tight" is in reference to the supply of aluminum. A "tight" market is one where consumption outpaces production, and there is upward pressure on prices.)[602]

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[597] Ex. 608, p. 10, l. 18-19.
[598] *Id.*, l. 19 to p. 11, l. 3.
[599] Tr. p. 2202, l. 7 to p. 2203, l. 11.
[600] Ex. 19, p. 3, l. 13-17; Tr. p. 2144, l. 2-22.
[601] *See, e.g.* Ex. 19, p. 5, Figure 1 (Humphreys Rebuttal, comparing Boyles' A2 case to CRU forecast).
[602] Ex. 601, p. 7, l. 16-23 (Boyles Surrebuttal).

Mr. Boyles' hypothesis of downward departures from CRU's forecast is invalid because he makes two fundamental errors. First, he ignores the fact – discussed above – that CRU has already factored supply and demand conditions into the CRU forecast. Mr. Boyles admits that CRU already considered these conditions:

> **Q. So when we're looking at these green bars [shown in Humphreys Figure 1] which are CRU's forecast numbers, they already have this no tight market condition built in best of your belief, correct?**
> A. Best of my knowledge. But it doesn't factor in all volatility.[603]

By assuming that "tight" market conditions justify downward pricing assumptions, Mr. Boyles is effectively double-counting in that he takes CRU's forecast (which includes consideration of these market conditions) and then postulates an even lower price based on the same market information.

Mr. Boyles also simply misinterprets Mr. Pratt's statement. Mr. Boyles relies on this statement to justify a hypothesis of a multi-year downward departure from CRU's forecast prices. But Mr. Pratt didn't say "downward trend" in pricing. At most, he said "less chance of an upward trend." Mr. Boyles actually understood this: "tight" means "there did not seem to be upward pressure on pricing to raise prices."[604] In cross-examination, Mr. Boyles went on to admit that he understood Mr. Pratt's quote as meaning that there would be "no significant upward or downward trends" for 2016 or 2017.[605] Mr. Boyles admitted that Mr. Pratt did not tell him that prices were going down in 2015, 2016 or 2017.[606] Noranda's management, moreover, had no basis to disagree with CRU's

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[603] Tr. p. 2515, l. 17-22.
[604] Tr. p. 2514, l. 2-4.
[605] *Id.*, l. 7-14.
[606] Tr. p. 2515, l. 23 to p. 2516, l. 2.

forecast of stable prices.[607] Despite this, Mr. Boyles' three scenarios show dramatic downward departures from CRU's forecast for multiple consecutive years after 2015.

In addition to misinterpreting Mr. Pratt's "no tight market" reference, Mr. Boyles also simply ignores his company's own repeated statements regarding positive demand factors in the markets Noranda serves. Mr. Boyles believes that there is a positive demand trend for Noranda's products over the next several years.[608] He testified that Noranda's local supply and demand fundamentals are positive.[609] In fact, Noranda's public statements consistently express a view that demand conditions in Noranda's US markets are positive.[610]

Mr. Boyles, in short, presents scenarios of downward prices that are unsupported by data, expert opinion, or Noranda's own market views. While he claims it is just a coincidence that the three scenarios he selected had the worst hypothetical cash flows, liquidity and net income results, the record shows otherwise. These scenarios were designed, at best, to paint a falsely alarmist picture.

iv. <u>Noranda's attempts to bolster the scenarios by claiming CRU's "close" involvement fall flat</u>.

Undoubtedly recognizing the fundamental flaws in Mr. Boyles' analysis, as well as Mr. Boyles' lack of experience and expertise in aluminum markets' modeling, Noranda attempted to bolster Mr. Boyles' analysis by claiming, in opening statement, that Mr. Boyles worked "closely" with CRU.[611] However, when questioned about this assertion, Mr. Boyles' characterization changed significantly:

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[607] Tr. p. 2511, l. 3-9.
[608] Tr. p. 2538, l. 12 to p. 2539, l. 10.
[609] Tr. p. 2555, l. 14-19.
[610] *E.g.*, Tr. p. 2550, l. 14-22; Ex. 69, p. 3; Ex. 70, p. 4.
[611] Tr. p. 2228, l. 15-16; Tr. p. 2503, l. 4-8.

> **Q. You told us in your testimony, and I think we heard in opening too, that you worked closely with CRU.**
> A. Yes, we worked closely with.
>
> **Q. Did you work closely with CRU before you filed your direct testimony?**
> A. We certainly had conversations, yes.
>
> **Q. You had some conversations.**
> A. Yes.
>
> **Q. You talked to them a little bit.**
> A. Yes.[612]

Questioned further, Mr. Boyles could not explain why, if CRU had worked "closely" with him to develop his analysis, he put forth an analysis in his direct testimony that attracted Mr. Pratt's criticisms as set forth in Mr. Pratt's later-filed surrebuttal.[613] Noranda's attempt in opening statement to bolster Mr. Boyles' analysis fails to convince, and in fact implicitly acknowledges the weaknesses of the argument. Counsel's statements certainly are not supported by evidence of record. Indeed, if Mr. Boyles worked closely with CRU in developing his direct testimony, then why did not his direct testimony, and Mr. Pratt's, reflect an endorsement by CRU of Mr. Boyles' approach, never mind Mr. Pratt's later criticisms of the approach.

C. Even if Mr. Boyles properly hypothesized possible price paths, Noranda's analysis is fatally flawed because it assumes Noranda would spend **[redacted]** in annual capital expenditures regardless of Noranda's circumstances.

After deriving his hypothesized aluminum prices, Mr. Boyles placed those prices into Noranda's "Enterprise Model" together with other assumptions he made to derive his hypothetical liquidity scenarios.[614] A critical assumption was that Noranda would spend at

[612] Tr. p. 2513, l. 10-20.
[613] Tr. p. 2516, l. 10 to p. 2521, l. 2.
[614] Tr. p. 2523, l. 2-21.

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least **[redacted]** annually in each of the next ten years that Mr. Boyles projected.[615] As Mr. Boyles admits, this is just an assumption for purposes of the model, as there is no contractual or legal requirement that that sum must be spent.[616]

In fact, history does not support Noranda's claimed capital expenditure amounts. In the past three years, Noranda's capital spending fell short of **[redacted]**: $88 million (2012), $73 million (2013), and $94 million (2014).[617] Prior to 2012, Noranda's capital expenditures were even lower – between $40 million and $65 million annually, and averaging $40 million per year.[618] Of Noranda's assumed future capital expenditures, approximately **[redacted]** in growth capital remains unspecified, with no discernable impact on production…and remote in time (2019-2021)."[619] When pressed in discovery for details as to this claimed departure from historical practice, Noranda could not provide specific plans beyond 2015, and could not provide specifics or financial justification for much of this expense.[620] Noranda's claimed amount for "catch-up" capital expenditures likewise lacks substantiation.[621] Also noteworthy is that none of Noranda's experts purport to have independently examined or verified Noranda's future capital expense claims. Merely excluding the **[redacted]** in unspecified capital expenditures from Noranda's model adds **[redacted]** to Noranda's hypothetical liquidity.[622]

Noranda not only assumes extraordinary and unexplained future capital expenditures, but assumes that those capital expenditures will continue at the **[redacted]

[615] Tr. p. 2560, l. 7-20.
[616] Tr. p. 2560, l. 21 to p. 2561, l. 6.
[617] Tr. p. 2633, l. 2-11. And 2015 saw large expenditures on the rod mill, which reflects a major expansion of Noranda's New Madrid operations and which itself will add significant profits for Noranda. Tr. p. 2635, l. 5-8.
[618] Ex. 33, Schedule RSM-R2, p. 20, Figure 2 and p. 20, l. 5 to p. 21, l. 2.
[619] Ex. 33, p. 21, l. 14-17.
[620] Ex. 33, p. 21, l. 17 to p. 22, l. 7.
[621] Ex. 33, p. 23. l. 1 to p. 24, l. 3.
[622] Ex. 33, p. 22, l. 8-9; p. 23, Table 5.

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[redacted]** annual level even if such expenditures push Noranda into a hypothetical liquidity crisis:

> **Q. Your model when you worked all the way through it and came up with some of these scary liquidity numbers, that was with an assumption that despite those numbers you were still going to spend **[redacted]** in capex in that year, correct?**
> A. That's correct. We deferred so much capital -—[623]

Thus, in order to accept Noranda's hypothetical liquidity crisis, one must first accept that Noranda would not attempt to avoid that crisis.

An assumption that Noranda would do nothing to avoid a hypothetical liquidity crisis is not reasonable or warranted. Noranda has, in the past, managed its capital expenditures:

> **Q. In fact there's been prior years where Noranda's deferred capex and paid large dividends to Apollo and other shareholders, correct?**
> A. I can answer the last part, there have been years when they deferred capex, I don't know if they used that money for paying dividends, that was prior to my time.[624]

Mr. Boyles, when questioned, agreed that Noranda could likewise manage its future capital expenditures:

> **Q. You don't have to keep your pedal, your foot on the gas pedal and spend **[redacted]** every year even if doing so would put you in default, correct?**
> A. That's correct. We do have some flexibility[625].

Moreover, Noranda's asserted **[redacted]** annual capital expenditure obligation is fundamentally inconsistent with its statements to other constituencies. In particular, in January, 2014, Noranda projected capital expenditures in a presentation to Moody's. In that presentation, Noranda's projected capital expenditures were significantly

623 Tr. p. 2562, l. 19 to p. 2563, l. 1.
624 Tr. p. 2562, l. 11-18.
625 Tr. p. 2562, l. 5-10.

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lower (on average, **[redacted]** per annum lower) than Noranda's hypothetical **[redacted]**.[626] This Commission has previously noted Noranda's statements to Moody's regarding lower capital expenditures, as well as Noranda's representations to investors that "sustainable capital expenditures should be in the range of $65 to $75 million per year.[627]

Noranda's liquidity scenarios, in short, assume illogical and self-destructive conduct in order to create the illusion of a likely liquidity crisis.

D. Even if Noranda's hypothetical prices are assumed, and Noranda is assumed to take no action to avoid a liquidity crisis, neither the record, nor logic, support a claim that the Smelter would inevitably close.

Put simply, there is no credible evidence that Noranda intends to close the smelter. While Opening Statements were emphatic that the smelter **[redacted]** the evidence tells a different story. In cross-examination, Mr. Boyles admitted that closing the smelter is not Noranda's only option:

> **Q. If Noranda defaults closing the smelter is not your only option.**
> A. There are other options.
>
> **Q. For example restructuring, correct?**
> A. Yes, I guess that's an option. I'm not sure how viable that options is, but yes, it's an option.
>
> **Q. It's an option you mentioned in your 10K.**
> A. Yes.
>
> **Q. So it's viable enough you told the SEC about it?**
> A. Yes. But there's a range of options, some are more viable than others.
>
> **Q. Negotiating with creditors, that would be another option.**
> A. That's correct.
>
> **Q. Selling the smelter, right, that would be an option?**
> A. That's an option.

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[626] Ex. 33 Schedule RSM-R2, p. 20, Figure 2 and l. 5-8.
[627] *Report and Order*, File No. EC-2014-0224, at Finding of Fact #19.

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Q. Somebody owned that smelter before Noranda did.
A. That's correct.

Q. You've made money at that smelter.
A. Yes.[628]

In fact, Noranda has not even really considered its options with respect to the smelter.[629] Noranda has made no calculations of the impact on EBITDA, cash flow, net income or liquidity entailed by a smelter closure.[630] Noranda has not performed a "shutdown analysis."[631] Mr. Smith acknowledged this complete lack of a shutdown plan:

Q. What about a plan as to liquidating the plant and equipment at the facility, moving employees, et cetera, is there a plan for any of those acts?
A. No. We don't have those plans developed yet….[632]

Logically, if Noranda actually anticipated any actual risk of a shutdown, it would have a plan in place. Noranda's response to a question from the bench illustrates this:

Q. So then it would seem to me to be a prudent business practice to have a contingency and maybe that contingency is a shutdown and then it would seem to me that you would have a plan in place or at least have the rudimentary principles lined out so that you would know what your options are going forward but you don't have a shutdown plan.
A. No, we haven't prepared a detailed analysis of shutting down the smelter.[633]

The evidence supports the conclusion that Noranda doesn't have a plan because it knows the smelter is not closing.

Moreover, it defies logic to suggest that Noranda would selectively close the smelter. Noranda is a vertically integrated aluminum manufacturer that mines bauxite, refines it into alumina, smelts the alumina into aluminum and then sells or further

[628] Tr. p. 2563, l. 13 to p. 2564, l. 12.
[629] Tr. p. 2564, l. 13-25.
[630] Tr. p. 2565, l. 1-22.
[631] Tr. p. 2565, l. 9-14.
[632] Tr. p. 2439, l. 16-21.
[633] Tr. p. 2598, l. 14-23.

processes the aluminum it makes.[634] It enjoys significant cost advantages from this vertical integration.[635] Noranda, however, would have the Commission believe that it would continue its other operations (mining, refining, and finishing) while shutting down the smelting operation that sits squarely in the middle of its vertically-integrated production chain. Such a claim makes no sense, and Noranda provides no evidence to support it.

E. Noranda continues to tell the Commission a different story than it tells the world.

This Commission has, in the past, recognized the fundamental inconsistencies between Noranda's dire claims before this Commission and its representations to investors, rating agencies and other outside constituencies.[636] Those inconsistencies continue.

In this case, Noranda asserts that it is clearly in a **[redacted]**.[637] In its February, 2015 presentation to investors, Noranda painted a far different picture. Mr. Smith told investors that Noranda's businesses "are in an improving trend."[638] Noranda reported sequential and year-over-year improvements in operating results.[639] According to Mr. Boyles, Mr. Smith was telling investors that the company was going in a good direction.[640] Noranda told investors it was

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[634] *Report and Order,* File No. EC-2014-0224, at Finding of Fact #2.
[635] Ex. 33, p. 7, l. 13-20; p. 41, l. 11-16.
[636] *E.g. Report and Order*, File No. EC-2014-0224, at Findings of Fact #14 (different financial model used with Moody's), #15 & #19 (different capital expenditure assumptions told to Moody's and to investors), #16 (different aluminum price projections provided to Moody's).
[637] *E.g.* Tr., p. 2569, l. 5-11; Tr. p. 2570, l. 16-21.
[638] Ex. 69, p. 5; Tr. p. 2581, l. 2-7.
[639] Ex. 69, p. 2; Tr. p. 2579, l. 10-16.
[640] Tr. p. 2579, l. 17-23.

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"targeting to improve segment profit by 85 million between now and 2016.[641] As Mr. Boyles admits, Noranda told investors a "positive message" about the future.[642]

Tellingly, Noranda has zealously guarded the negative story it has put before this Commission, repeatedly asserting that this information is "Highly Confidential." It has done this because this information differs substantially from the information that Noranda puts into the public domain. As an indicator of these differences, Noranda presents no evidence that its allegedly present, dire and certain liquidity crisis has caused Noranda to file an 8-K as required by Federal Securities law, a glaring inconsistency that this Commission also saw in Noranda's prior case.[643]

These discrepancies are telling. In Noranda's last case, this Commission concluded that "the financial projections Noranda has presented to its investors, and to Wall Street in general, cast considerable doubt on the financial projections it presented to this Commission."[644] Noranda's credibility has not improved, and this most recent attempt to yell "FIRE!" is no more convincing than the last.

F. Noranda's claim is consistent with past history.

If Noranda does not, in fact, sit at the precipice, then another reason must exist for Noranda's persistent attempts to manufacture grounds to obtain cheaper electricity at other ratepayers' expense. Noranda's public statements, together with its history, provide an answer.

In its most recent investor call, Noranda repeatedly stated that its promising prospects served a key goal: enhancing shareholder value. As stated by Mr. Smith, "we are

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[641] Tr. p. 2580, l. 20-25; Exh. 69, p. 4.
[642] Tr. p. 2582, l. 16-20; *see also* Tr. p. 2582, l. 8-15.
[643] *Report and Order*, File No. EC-2014-0224, at Findings of Fact #25.
[644] *Report and Order*, File No. EC-2014-0224, p. 26.

positioned *to build shareholder value* by improving our profitability and generating positive cash flow in 2015."[645]

Chief among these shareholders is Apollo. Apollo still owns about a third of Noranda's stock.[646] Moreover, according to Noranda's recent S.E.C. filings, Apollo: "has the ability to substantially influence our company and the outcome of matters voted upon by our shareholders and to prevent actions which a shareholder may otherwise do favorably."[647] Likewise, "Apollo has the ability to significantly influence our decisions."[648]

This Commission is very familiar with Apollo. Apollo's history with Noranda was well-described in the Commission's August, 2014 Order:

> 28. Noranda was purchased from its previous owner by Apollo Management, L.P., a private equity investment fund, on May 18, 2007. In a deal valued at $1.165 billion, Apollo paid $214.2 million in equity and the balance was from debt secured by Noranda assets and operations. Twenty-five days later, on June 12, 2007, Noranda borrowed money to pay Apollo a dividend of $214.2 million. Thereafter, while still owning stock in the company, Apollo has fully recovered its investment and currently has no equity invested in the company. Noranda was left with a capital structure of nearly 100 percent debt.
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> 29. But Apollo was not done taking cash out of Noranda. On June 13, 2008, Noranda paid Apollo another dividend of $100.7 million. Noranda conducted an Initial Public Offering (IPO) of one third of its equity in Noranda on May 19, 2010. After the IPO, Apollo received additional dividends of $107.9 million, as well as $151.1 million from the secondary sale of Noranda stock. In all, Apollo has realized dividends of $422.8 million and realized stock sale proceeds of $151.1 million, while still retaining 34 percent of Noranda's stock. In addition, Noranda has paid Apollo $31 million in management fees since the acquisition. As of the end of 2013, Noranda's ratio of long term liabilities to book capitalization is 87 percent.

[645] Tr. p. 2583, l. 14-20; Exh. 69, p. 7.
[646] Tr. p. 2485, l. 5-11.
[647] Tr. p. 2486, l. 24 to p. 2487, l. 10; Ex. 533, p. 22.
[648] Tr. p. 2487, l. 15-19; Ex. 533, p. 22.

30. Because of its debt, Noranda must pay roughly $50 million per year in interest payments.[649]

To the extent Noranda is in an uncomfortable liquidity position that discomfort is, as the Commission aptly stated, "largely self-inflicted."[650] In its August, 2014 Order, the Commission noted that, as far back as 2010, Noranda was telling this Commission that electric rates threatened its very survival: "[t]his is not the first time that Noranda has argued to the Commission that it must have a lower electric rate if its New Madrid smelter is to survive."[651] Notably, after its 2010 IP, Noranda declared a "special dividend" of $107 million.[652]

The evidence in this case demonstrates that Noranda is no closer to closing the smelter in 2015 than it was in 2010. Rather, Noranda is in an enviable cost position, with its smelter enjoying the **[redacted]** overall cost of any US smelter (a position that will only further improve should Noranda receive lower electric rates).[653] Ameren respectfully submits that the evidence in this case demonstrates two things. First, that Noranda has not met its burden to show that rate relief is necessary to prevent Noranda's failure. And second, that providing Noranda low cost electricity for the next seven years will clearly "build shareholder value." While that may be Noranda's goal, it is not one that should be met at the expense of Ameren's other customers.

III. FLAWS IN NORANDA'S CUSTOMER BENEFIT ANALYSIS

Even if the Commission could provide the requested relief, even if Noranda really were in a dire financial condition and even if all the facts justify the Commission granting some type of relief to Noranda, the fact remains that Noranda's proposal does not leave customers better off than if the smelter were to close and cease taking service from Ameren Missouri. The reality is

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[649] *Report and Order*, File No. EC-2014.0224, at Findings of Fact #28-30.
[650] *Id.*, p. 26, fn. 86.
[651] *Id.* at Finding of Fact #26.
[652] *Id.*, at Finding of Fact #29.
[653] Ex. 33, p. 40, Fig. 4.

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that the relief proposed (whether one is looking at the seven-year or ten-year proposal) in this case leaves customers worse off than if the smelter were closed immediately (a worst case scenario that even Noranda does not claim will occur.) Mr. Michels' analysis of the seven-year proposal shows a detriment to customers of $272 million when comparing the cost to other customers of Noranda's proposal compared to the cost to other customers if the smelter ceased operation.[654] Under the terms of the ten year proposal, customers are even worse off, with that proposal costing customers $550 million as compared to the cost if the smelter ceased operation.[655]

Noranda's witnesses on this issue, Mr. Dauphinais and Mr. Brubaker, only undertook historical analyses and failed to consider the actual terms of the Noranda proposal and the impact those terms would have going forward.[656] The Commission recognized this same inadequacy in its *Report and Order* in the complaint case last summer. In that order, the Commission stated that the value of historical calculations are limited because they make "no attempt to determine how the cost to serve might change" over a period for which the non-cost based rate is sought.[657] Staff's analysis also suffers from this limitation and cannot provide a basis for a forward looking rate.[658] As Mr. Davis pointed out, even Staff's calculations would result in a rate that is below cost of service and, in fact, likely far below cost of service[659] which would not be reflective of future costs over the requested term.[660] In response to these criticisms, Messrs. Brubaker and Dauphinais defended Noranda's proposal by pointing out that the Commission can alter the rate

[654] Ex 26, p. 29, l. 4-5.
[655] Tr. p. 2931, l. 3-14.
[656] Ex. 26, p. 22, l. 16 to p. 23, l. 2; Tr. p. 2979, l. 17 to p. 2980, l. 23.
[657] *Report and Order*, File No. EC-2014-0224, p. 18, ¶43.
[658] Ex. 27, p. 10, l. 4-15.
[659] Ex. 9, p. 21, l. 9-13.
[660] Ex. 27, Schedule MRM-S3.

in any future rate case.[661] Of course, if they really believed there is a real chance the Commission would alter Noranda's rate in the future (assuming it is even granted in this case), then Noranda's proposal cannot offer the long-term, stable rate it claims it needs to address its alleged financial problems. The reality is somewhat different from this claim, however. Despite admonitions that this Commission cannot bind a future Commission, it is unlikely that once relief is granted, it will be undone, so relying on recent history to establish prices "only until the next rate case" is detached from the realities of the request.[662] And without a defined path back to cost of service rates, the subsidy – which will likely grow over time – will likely continue beyond the seven (or ten) years requested by Noranda.[663] This Commission pointed to this very concern in its findings of fact in the Report and Order from the complaint that was heard last summer:

> Moreover, as a practical matter, it is unlikely that the subsidized rate given to Noranda could be ended after ten years. By that time, the rate Noranda would be paying would likely be even further below Ameren Missouri's actual cost to serve the company. If Ameren Missouri's general rates increased by six percent every other year, while Noranda's rates were allowed to increase by only two percent every other year, at the end of ten years, the rate Noranda pays would be nearly 34 percent below its cost of service. Clearly, Noranda would not be willing, or able, to withstand a 34 percent rate increase in year eleven to return to cost-based rates. As a result, the subsidy could, in effect, become permanent.[664]

Finally, in his surrebuttal testimony, Mr. Dauphinais at long last makes an attempt to evaluate future power prices and compared Noranda's average rate under its seven-year proposal to the average avoided cost over seven years, reflecting all of his adjustments to Mr. Michels'

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[661] Ex. 26, p. 23, l. 17 to p. 24, l. 13.
[662] Tr. p. 2942, l. 9-16.
[663] Ex. 9, p. 22, l. 19 to p. 23, l. 7.
[664] *Report and Order*, File No. EC-2014-0224, p. 14, ¶34.

prices.[665] Even in this analysis, Mr. Dauphinais had to admit that the average adjusted price was $0.35/MWh higher than Noranda's proposal.[666] If one removes his inappropriate adjustments, it would further exacerbate the cost disadvantages of Noranda's proposal for other customers. For example, Mr. Dauphinais argues that capacity prices in other zones in MISO may be much higher than in Zone 5[667] and points out that Ameren Missouri has to import capacity from Zone 4 to meet resource obligations.[668] Yet, if Noranda went out of business, that capacity would be freed up and reduce the amount imported to Zone 4 as well as freeing up that capacity for sale in Zone 4.[669] What Mr. Dauphinais misses in his argument is that Zone 4 is a restructured market in Illinois and, as such, is subject to significant capacity price pressures going forward, such as the bidding of capacity into PJM, the potential that Illinois may move to PJM and, of course, potential retirements of coal and nuclear generation.[670] All of these factors would create significant upward pressure on the prices Ameren Missouri would realize from the sale of capacity made available by the loss of Noranda's load, making the opportunity cost to serve Noranda even higher.

Additionally, Mr. Dauphinais' downward adjustment of energy prices tied to a scenario where the smelter closes is erroneous. His analysis does not compare prices with and without Noranda. His analysis could not have considered prices without Noranda because his work was based solely on historical data that only includes Noranda in operation.[671] Mr. Dauphinais agreed with Mr. Michels that doing a PROMOD analysis would be appropriate for determining

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[665] Ex. 509, p. 25, l. 11. (Dauphinais Surrebuttal).
[666] Ex. 509, p. 25, l. 12-13
[667] Ex. 509, p. 24, l. 7-10.
[668] Tr, p. 2866, l. 16-24; Tr. p. 2868, l. 7-11.
[669] Tr, p. 2986, l. 13-17.
[670] Tr. p. 2986, l. 17 to p. 2987, l. 11.
[671] Ex. 508, Appendix C, p. 2, l. 1-15 (Dauphinais Direct).

price impacts of such an occurrence, but no such analysis was ever performed.[672] Mr. Michels did a similar analysis using a MIDAS model, which yielded a price impact of only 0.15%, as compared to Mr. Dauphinais' unsupported estimate of 1.5%.[673]

Ameren Missouri was not attempting to predict a future avoided cost but rather attempted to create a benchmark by which to measure the reasonableness or unreasonableness of Noranda's request. Ameren Missouri's benchmark calculation of avoided costs for the seven years of Noranda's proposal is $42.73/MWh.[674] The difference between that price and the $39.58/MWh (which is Dauphinais' price once the inappropriate adjustments are removed) is that Dauphinais' future power prices are based upon current forward prices for energy. While forward energy prices are representative of the price that parties may be able to contract for today, without locking in those prices and paying the premium described by Mr. Phillips,[675] they are subject to risk in the same way that aluminum prices are subject to risk.[676]

As is described above, there are a multitude of reasons that Mr. Dauphinais' calculations are not an accurate reflection of Ameren Missouri's avoided costs. Yet, Noranda has not addressed or evaluated in any other manner the potential risk to other customers if the avoided costs are different than what Mr. Dauphinais estimates. All of these factors paint Mr. Dauphinais' numbers as an insufficient foundation upon which to rely for approval of Noranda's proposal.

In summary, the financial condition faced by Noranda today is not worse than that it was facing last summer; indeed, it is arguably better. Moreover, the proposal set forth by Noranda leaves customers worse off than they would be if Noranda shuttered its plant.

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[672] Ex. 509, p. 19, l. 1-8
[673] Tr. p. 2984, l. 11-15.
[674] Ex. 509, p. 21, l. 1-2.
[675] Ex. 516, p. 14, l. 5-9 (Phillips Surrebuttal).
[676] Tr. p. 2985, l. 3-15.

The Commission cannot and should not grant Noranda its requested relief, largely for the same reasons it could not and did not last summer. As the Commission stated in the Summary section of its order rejecting a very similar request for relief last summer:

> Complainants' request is founded on three contentions: 1) Noranda Aluminum, Inc.'s aluminum smelter is crucial to Missouri's economy; 2) the smelter cannot be sustained without the rate relief requested; and 3) all Ameren Missouri ratepayers will directly benefit from the relief requested because granting that relief is more beneficial compared to Noranda leaving the Ameren Missouri system. While there is substantial evidence in the record regarding the impact of the smelter on southeast Missouri and on the state, the evidence does not support the second and third of Complainants' contentions. Accordingly, the Commission finds that the Complainants have failed to carry their burden to show that Ameren Missouri's rate design should be modified, contrary to traditional cost of service principles, in order to give a reduced rate to Noranda Aluminum, Inc.[677]

The record in this case on this issue dictates the same findings here, and perhaps even more strongly.

IV. COMMISSIONER HALL'S NORANDA SUBSIDY REQUEST-RELATED QUESTIONS

At the conclusion of the evidentiary hearings, Commissioner Hall requested responses to several questions related to the Noranda proposal and, in addition, to the wholesale option that had been discussed by Ameren Missouri but about which an agreement was not reached with Noranda. Set forth below are the questions (in italics) followed by the Company's responses.

> ***I want to know what is this risk concern that Ameren [Missouri] and Noranda have concerning the wholesale agreement proposal that Ameren [Missouri]'s put forth, and to what extent the Commission in an Order or a tariff could mitigate or eliminate that risk. I'm also curious as to what extent the General Assembly can mitigate or eliminate that risk.***

The primary issue was the question of who would bear the risk of a major change in circumstances that would render the contract either invalid or leave Ameren Missouri with costs not being covered by the contract and retail revenues it would receive during the contract term. As Mr. Brubaker alluded to during the hearing, Noranda in particular had concerns about

[677] *Report and Order*, EC-2014-0224, p. 3-4.

whether a court could determine that the wholesale arrangement, with the costs and revenues flowing through Ameren Missouri's fuel adjustment clause, was somehow unlawful. Specifically, as Ameren Missouri understood it, the concern was whether a court could determine that the enabling statute for the FAC was not broad enough to include the costs and revenues for this type of transaction. Ameren Missouri was most concerned with the risk that a party to one of Ameren Missouri's future rate cases (as some parties did in this case) would advocate to remove such a contract's costs and revenues from the FAC, which would (absent appropriate protections in the contract itself) put Ameren Missouri at risk of incurring costs under the contract that exceeded its revenues for a contract that Ameren Missouri had been willing to enter into even though it would be below the cost to serve Noranda. While the degree to which it would have been below the cost to serve Noranda would have been materially less than the difference between cost of service and the prices reflected in either of Noranda's seven or ten-year proposals,[678] it still would have been less. Agreement could not be reached on addressing these risks. From the Company's perspective, it was inappropriate for the Company to bear any such risks because aside from resolving this ongoing Noranda issue (which the Company read the Commission's *Report and Order* in File No. EC-2014-0224 as encouraging the parties to do if possible) entering into a contract to give Noranda some relief as compared to simply reflecting its cost of service through its retail rates would provide no financial benefit to Ameren Missouri.[679] It should also be noted that logically, even if the risks Noranda was

[678] Ex. 29, p. 14, l. 4-8. (Moehn Surrebuttal) (Any price Ameren Missouri would have been willing to agree to would have been higher than being proposed by Noranda, including higher than the latest proposed price,)

[679] The point of the proposed wholesale agreement was primarily threefold. First, as an attempt to "solve" the ongoing Noranda issue, as noted. Second, to solve it with some rate relief, but only as indicated by the market at the time of contracting based on the length of the term of such a contract, which from the Company's perspective avoided the severe problems a retail rate subsidy presented in light of the regulatory compact that governs setting retail rates. And third, since that market price was materially higher than the subsidy Noranda sought, while customers would still provide a subsidy, it would have been less than Noranda was seeking.

concerned about were realized, the result would likely have been that Noranda would simply have to pay a Commission-determined retail rate.

Regarding the question of whether the Commission could eliminate or mitigate these risks, in general the answer is likely "no." The FAC enabling statute provides for what it provides, and revenues and expenses eligible for inclusion in a FAC are what they are. The Commission has no power to change that.[680] As for the issues of removing costs and revenues from the FAC, the Commission could rule not to do so, but even if the Commission today indicated an intention not to do so, such an intention might not be followed later, meaning some risk would remain.

As for whether the General Assembly could eliminate or mitigate such risks, the answer is "yes." *If* there currently are statutory issues regarding such a contract and a FAC, statutory changes could be made. Moreover, the General Assembly could adopt legislation that prescribes how such a contract is treated for retail ratemaking purposes. Indeed, the General Assembly could essentially adopt legislation that addresses Noranda's claimed need and request however it wants. The Company has been consistent in indicating that this is precisely what should occur (and frankly what has to occur) if a rate subsidy of the type Noranda seeks is to be granted.

Second issue, how and to what extent would ratepayers be harmed by moving Noranda to wholesale service. Can the Commission or General Assembly mitigate or eliminate that harm?

Given Mr. Moehn's testimony that any such wholesale contract the Company would have entered into would have been at a higher price (i.e., at market-based prices for the term) than the rate requested by Noranda in its proposal, the answer is "no." While the contract price would

[680] This is not to say that the Commission's application of such a statute is completely irrelevant to what the statute does or does not provide for. Under some circumstances it is, but in the end, if the question is a legal one – as Noranda was concerned it was – then the resolution of the question would be for the courts regardless of what the Commission said or did.

have been less than the retail rate meaning that other customer rates would have gone up some in this case, the impact would have been less than the subsidy Noranda seeks, and even if Noranda were to close the smelter, ratepayers would continue to benefit from revenues in the FAC.

Respectfully submitted:

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Dated: March 31, 2015

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of the foregoing document was served on all parties of record via electronic mail (e-mail) on this 31st day of March, 2015.

/s/James B. Lowery
James B. Lowery