BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase its Revenues for Electric Service	))))	**Case No. ER-2014-0258**

INITIAL POST-HEARING BRIEF OF THE MISSOURI INDUSTRIAL ENERGY CONSUMERS

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Come now, the Missouri Industrial Energy Consumers, and for their initial post-hearing brief state as follows:

I. REVENUE REQUIREMENT

A. Amortizations

1. Introduction

Missouri law provides that commission-set rates "to be charged" must be just and reasonable, must be prospective only, and must be based upon "all relevant factors." *See* § 393.270. The Missouri Supreme Court stated it well in *State ex rel. Util. Consumers' Council of Missouri, Inc. v. Pub. Serv. Comm'n*, 585 S.W.2d 41 (Mo. banc 1979) ("*UCCM*") (striking down an automatic fuel adjustment surcharge not authorized by statute at the time):

> The commission has the authority to determine the rate [t]o be charged, § 393.270. In so determining it may consider past excess recovery insofar as this is relevant to its determination of what rate is necessary to provide a just and reasonable return in the future, and so avoid further excess recovery.[1]

The court was likewise clear that a utility's under-recovery is no basis for allowing it to collect "additional amounts":

> The utilities take the risk that rates filed by them will be inadequate, or excessive, each time they seek rate approval. To permit them to collect additional amounts

[1] *Id*. 585 S.W.2d at 58.

> simply because they had additional past expenses not covered by either clause is retroactive rate making, i. e., the setting of rates which permit a utility to recover past losses or which require it to refund past excess profits collected under a rate that did not perfectly match expenses plus rate-of-return with the rate actually established .… Past expenses are used as a basis for determining what rate is reasonable to be charged in the future in order to avoid further excess profits or future losses, but under the prospective language of the statutes, §§ 393.270(3) and 393.140(5), they cannot be used to set future rates to recover for past losses due to imperfect matching of rates with expenses.[2]

Sometimes utilities are allowed to "defer" certain extraordinary costs. The Court of Appeals explained this process well in *State ex rel. Aquila, Inc. v. Pub. Serv. Comm'n:*[3]

> We begin with some brief (and necessarily general) background. A regulated utility's rates are established prospectively in periodic ratemaking proceedings, based on the utility's revenues and expenses during an earlier "test year." When a utility incurs extraordinary expenses (such as the construction of major capital improvements) outside of a "test year," those extraordinary expenses will not be reflected in rates (because the rates were established to allow the utility to recoup its ordinary expenses, as reflected in the "test year"). An accounting authority order or "AAO" permits a utility to capture those extraordinary expenses for (potential) recovery in the forward-looking rates to be established at a future rate case (even though the extraordinary expenses may occur outside the "test year" utilized in that future rate case). As we explained in *Missouri Gas Energy v. Public Service Commission,* 978 S.W.2d 434 (Mo. App. W.D.1998), when a utility incurs extraordinary expenses associated with the acquisition or construction of a new, productive asset,
>
>> [t]he temporary problem created is the accounting treatment of the new asset until a new rate, after a hearing and subsequent order by PSC, goes into effect. The Commission has the regulatory authority to grant a form of relief to the utility in the form of an accounting technique, an Accounting Authority Order, (hereinafter called an "AAO") which allows the utility to defer and capitalize certain expenses until the time it files its next rate case. The AAO technique protects the utility from earnings shortfalls and softens the blow which results from extraordinary construction programs. However, AAOs are not a guarantee of an ultimate recovery of a certain amount by the utility.[4]

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[2] *Id*. 585 S.W.2d at 59 (citations omitted).

[3] 326 S.W.3d 20 (Mo. Ct. App. 2010).

[4] 326 S.W.3d at 28.

The granting of an AAO does not guarantee recovery; rather, it allows the utility to seek recovery during a future rate case. The Missouri cases are clear that in the future rate case considering such recovery, the Commission is to set rates by considering "all relevant factors."

In *State ex rel. Office of Public Counsel v. Public Service Comm'n of Missouri*, 858 S.W.2d 806 (Mo. Ct. App. 1993) ("*OPC 1993*"), the Court of Appeals rejected a claim that granting an AAO constituted single-issue ratemaking because it was not ratemaking at all. The court emphasized that whether the deferred amounts may be recovered is decided in a rate case, where all relevant factors may be considered:

> The Commission's order did not presume to determine a new rate but effectively permitted MPS the option to file a rate case … and then to present evidence and argue that the deferred costs … should be considered by the Commission in approving a rate change. <u>The Commission's order does not preclude consideration of other relevant factors</u>[.][5]

The court explained in note 1 of that decision that this Commission required the utility to begin amortizing (writing down) the deferred expense immediately but could not recover those expenses in rates unless it brought a rate case within one year of the deferral. In that rate case, the Commission would consider all relevant factors in deciding whether to allow recovery of the unamortized balance of the deferral. The Commission was particularly concerned "that a utility should not be permitted to save deferrals to offset excess earnings in some future period." Obviously this Commission was concerned about excess earnings and that is why it was incumbent on the utility to file a rate case, something that it certainly would not do if the result were to lower its rates.

Similarly, in *State ex rel. Office of Public Counsel v. Mo. Pub. Serv. Comm'n* ("*OPC 09*"), the Court of Appeals was clear that in the rate case considering recovery of deferred costs,

[5] 858 S.W.2d at 813 (emphasis added).

"the Commission will consider the deferred amount along with other relevant factors."[6] And as quoted in *State ex rel. Aquila, Inc. v. Pub. Serv. Comm'n*, *supra*, the Court of Appeals in *Missouri Gas Energy v. Public Service Commission,*[7] was clear that one purpose of an AAO was to protect the utility from earnings shortfalls:

> The AAO technique protects the utility from earnings shortfalls and softens the blow which results from extraordinary construction programs. However, AAOs are not a guarantee of an ultimate recovery of a certain amount by the utility.[8]

Obviously where a utility is overearning at the time of deferral, it does not need "protect[ion] … from earnings shortfalls[.]"

In *In the matter of the application of Missouri Public Service,* this Commission recognized that "[t]he deferral of costs from one period to another period for the development of a revenue requirement violates the traditional method of setting rates."[9] In allowing deferral, the Commission stated the following:

> Staff's emphasis on whether the utility was earning above its authorized rate of return at the time of the deferral, whether the expenditures are reasonable and prudently incurred, and whether to include carrying costs in the recovery are rate case issues and best left for rate case review.[10]

In a follow-up case, *In re Mo. Pub. Service, a Division of UtiliCorp United Inc.,*[11] this Commission allowed recovery of the deferred costs but only after considering past overearnings along with other relevant factors:

> The Commission finds that there are other factors besides earnings which must be considered in reaching a decision on the recovery of deferred costs. Of course, the earnings level of a company is the initial and primary focus. In this case, though,

[6] 301 S.W.3d 556, 567 (Mo. Ct. App. 2009).

[7] 978 S.W.2d 434 (Mo. Ct. App. 1998).

[8] 978 S.W.2d at 436 (emphasis added).

[9] Case No. EO-91-358 and 360, 1991 Mo. PSC Lexis 56 (page 4) .

[10] *Id*. at page 5.

[11] Case No. ER-93-37, 152 P.U.R.4th 333 (Mo. P.S.C. 1994).

> the evidence indicates that the period during which MPS was overearning, 1991, was a period when no AAO was in effect and no deferrals were occurring. This fact alone detracts significantly from OPC's position.[12]

In conclusion, both the courts and this Commission accept that an all relevant factors determination is appropriate when considering whether to allow recovery of deferred costs. Indeed, as indicated above, this Commission found that "in reaching a decision on the recovery of deferred costs …[o]f course … the earnings level of a company is the initial and primary focus."[13]

2. A Deferral Should Not Be Used As A Vehicle to Protect Overearnings

The rationale supporting an AAO certainly does not apply if the utility is already earning above its authorized return, even had it not deferred unexpected extraordinary costs. The Missouri Supreme Court has been clear that utilities may not recover past losses from future ratepayers, because that is retroactive ratemaking. *UCCM*, 585 S.W.2d at 59 ("[Past losses] cannot be used to set future rates to recover for past losses due to imperfect matching of rates with expenses"). Here, Ameren Missouri seeks to do much more than seek to recover "past losses." Here, during the periods when Ameren Missouri was deferring the subject costs (solar rebates, pre-MEEIA costs, Fukushima study costs, storm costs and vegetation management costs)[14] it was actually overearning and would have been overearning even without deferrals. Ameren Missouri seeks to use deferrals to enhance its already bloated earnings. In fact, Ameren Missouri's CEO Michael Moehn admitted that Ameren Missouri has actually been benefitting from regulatory lag.[15] Also of interest here is the CEO's admission that Ameren Missouri has no

[12] *Id.*

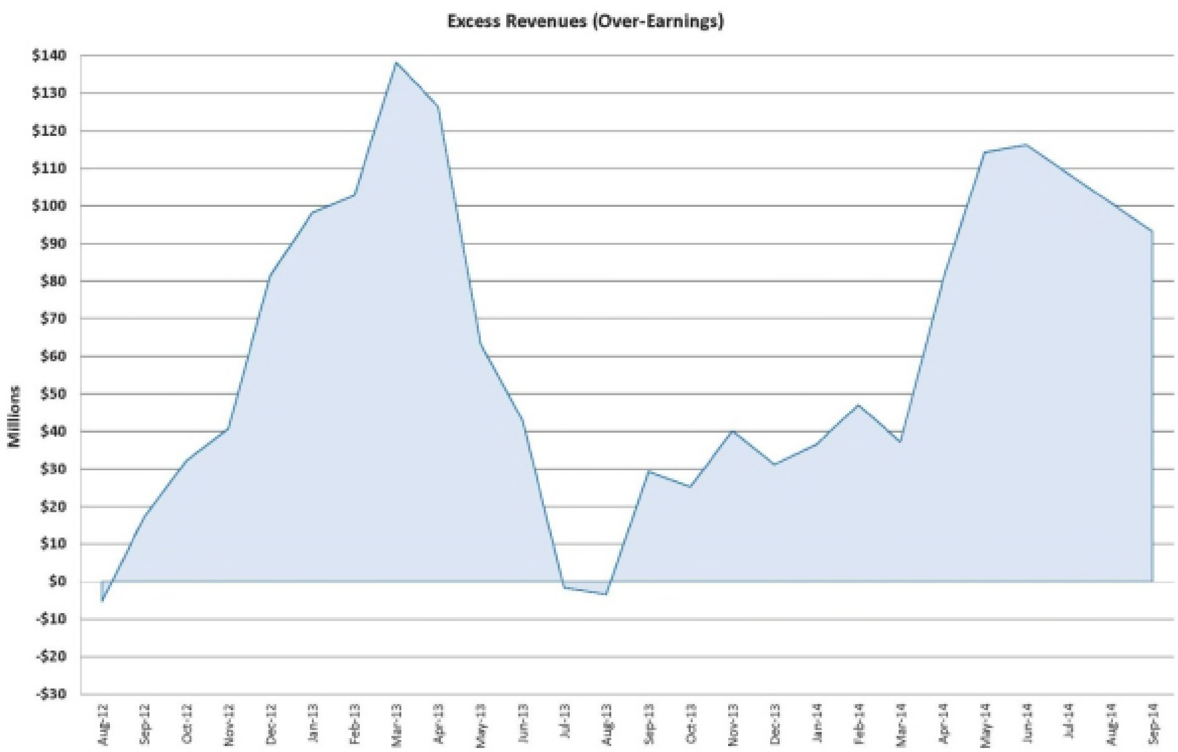
[13] *Id.*

[14] The Noranda AAO is addressed separately.

[15] Moehn testimony, Tr. p. 193, ll. 11-14.

interest in tracking or deferring cost savings that occur between rate cases, such as Ameren Missouri realized from its workforce reductions.[16]

Ameren Missouri has been overearning for almost the entire time that its current rates have been in effect and when the deferred costs at issue were incurred. Indeed, the testimony of Greg Meyer clearly bears this out. Below is a graph from Mr. Meyer's testimony[17] depicting Ameren Missouri's overearnings for twelve month periods ending August 2012 through September 2014.

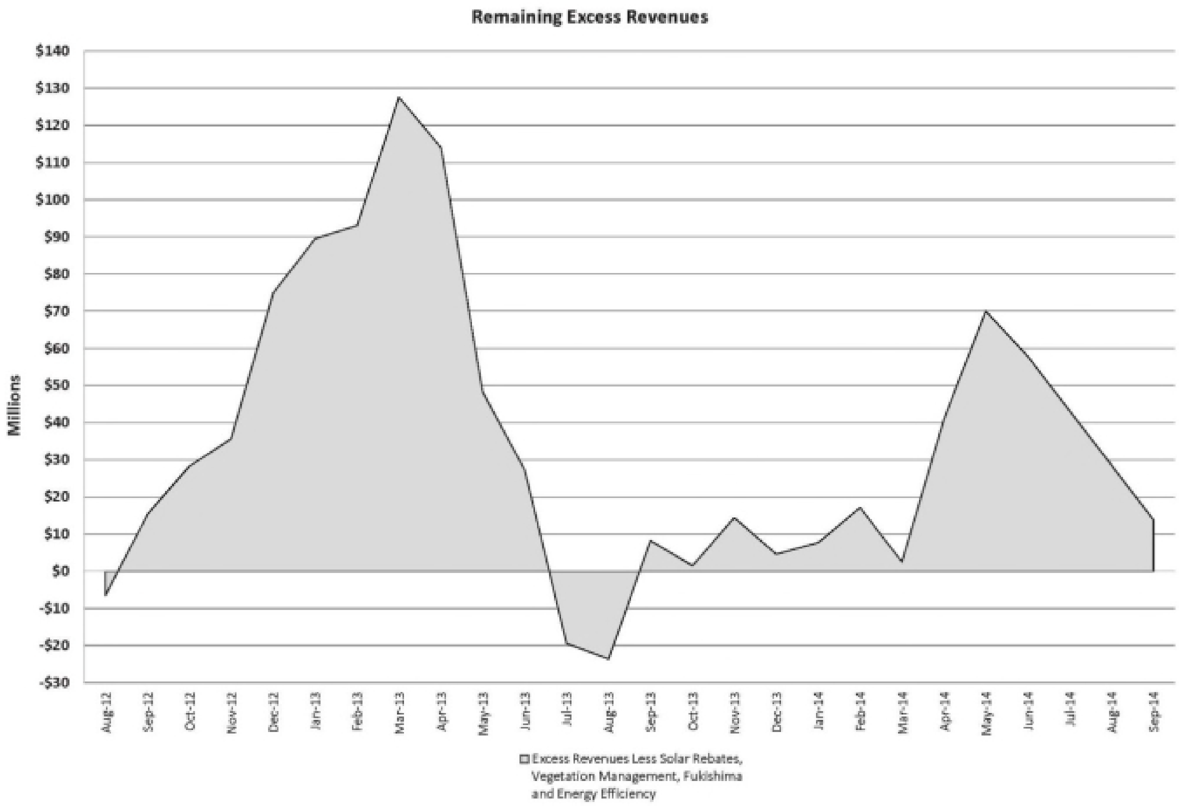


To be clear, this graph does not show Ameren Missouri's earnings; it shows the amount of its earnings exceeding its authorized return on equity (i.e. its authorized earnings). These overearnings are significant. The area under the curve and above $0 represents hundreds of

[16] Moehn testimony, Tr. p. 193, l. 15 – p. 195, l. 15.

[17] Meyer Direct, Ex. 513, p. 10.

millions of dollars, well more than the deferred amounts at issue here. This is evidenced by the following graph showing actual earnings if no deferrals had been allowed.[18]



As the above graph clearly shows, even had Ameren Missouri not deferred any of the subject costs and instead reported those costs when incurred, it still would have had substantial earnings above its authorized return on equity. Clearly Ameren Missouri needed no deferrals for "protect[ion] … from earnings shortfalls" as contemplated by the Court of Appeals in *State ex rel. Aquila, Inc. v. Pub. Serv. Comm'n, supra*.

And Mr. Meyer was not the only MIEC witness to address this issue. Mike Gorman also opined, consistent with the cases cited above, that there is no reason to allow recovery of deferrals when the utility is already overearning:

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[18] Meyer Direct, Ex. 513, Schedule GRM-4, p. 5 of 5.

> If the utility can expense the costs that are being deferred and still earn its authorized return on equity, then there's really no need for a deferral.
>
> A deferral is designed to protect the utility's earnings in the event the prices the customers are paying don't provide enough revenue to cover that cost….
>
> So I don't think it would be consistent with the objective of the regulatory commission to allow a utility to defer expenses during a period where the deferral was not necessary….
>
> To allow them to defer expenses under those scenarios would allow the utility to essentially recover the cost of those deferrals twice, the revenue they collected during the deferral period and then the revenue would be enhanced during the new rate effective period as the deferral was included in the new rate structure.[19]

The Commission's duty is "to balance the interest of the ratepayers with that of the shareholders." *State ex rel. Union Elec. Co. v. Pub. Serv. Comm'n of State of Mo*.[20] Ameren Missouri's shareholders have already earned their permitted returns even without the deferrals; this recovery of deferred costs from tomorrow's ratepayers amounts to double-recovery of those costs and is a veiled attempt to have this Commission abdicate its duty. The Court of Appeals has suggested that this Commission should in fact prevent such double-recovery. *See OPC 09.*[22] In that case, Public Counsel argued against allowing an AAO under the cold weather rule because it could allow double recovery of costs. In rejecting that argument, the Court of Appeals noted that the double recovery issue could be addressed in the rate case seeking recovery of the deferred costs:

> The Commission found some merit to the Public Counsel's argument that Laclede might possibly receive a double recovery if customers subsequently further paid down their past-due balances, but the Commission noted that this was a valid concern only if it is assumed that Laclede's cost amount will be passed through without further consideration in a future rate case. But, such is not the case. In Laclede's next rate case, the Commission will consider the deferred amount along with other relevant factors.[21]

[19] Gorman testimony, Tr. p. 1294, l. 13 – p. 1295, l. 17; p. 193, l. 15 – p. 195, l. 15.

[20] 765 S.W.2d 618, 625 (Mo. Ct. App. 1988).

[22] 301 S.W.3d at 567.

[21] *Id.* at 567.

This Commission has placed great emphasis on a utility's financial stability when permitting recovery of a deferred cost. *See, e.g., Re Mo. Pub. Service, a Division of UtiliCorp United, Inc.,*[22] (permitting recovery when deferral was of approximately 23% of utility's net income from electrical service). There, this Commission determined that a utility's recovery was permissible because there was "ample evidence of the significant impact of this enterprise [creating the losses] on Company's financial status." *Id.* Here, whether Ameren Missouri is allowed recovery or not, it will have earned more than its authorized return on equity.

Ameren Missouri will no doubt cite *In re Mo. Pub. Service, a Division of UtiliCorp United Inc., supra.*[23] There, an electric utility convinced the Commission, in a rate case, to grant recovery under an AAO despite a claim of potential overearnings. In that case, the parties agreed that the utility could raise rates anyway and the potential overearnings occurred during periods when there were no deferrals in effect. The Commission found that latter fact "detracts significantly from OPC's position [against recovery]." Moreover, that Commission was unimpressed with the evidence in that case. It found that the evidence included "minimal" analysis and did not show whether overearnings were excessive during part of the deferral period. The facts here are different. Here, the evidence clearly shows that without deferral of the subject expenses, Ameren Missouri still would have overearned by substantial amounts.[24] It makes absolutely no sense to charge tomorrow's ratepayers for expenses that will not be incurred to serve them. Ameren Missouri has made no claim that it will incur solar rebates, Fukushima study costs, pre-MEEIA costs or <u>extra</u> vegetation management or storm costs to serve tomorrow's ratepayers. This is particularly true here, where yesterday's ratepayers have already

[22] Case No. ER-90-101, 118 P.U.R.4[th] 215 (Mo. P.S.C. 1990).

[23] Case No. ER-93-37, 152 P.U.R.4[th] 333 (Mo. P.S.C. 1994).

[24] Meyer Direct, Ex. 513, Schedule GRM-4, p. 5 of 5.

paid sufficient rates for Ameren Missouri to have recovered these deferred costs and earned more than its authorized return on equity to boot.

3. The MIEC Is Not Precluded From Challenging the Solar Rebate Recovery

Ameren Missouri argues that the Stipulation on Solar rebates, which the MIEC signed, precludes its arguments here. That is not the case. At the time of that Stipulation, the MIEC could not know whether Ameren Missouri would overearn in the future when it was incurring additional solar rebate costs under the Stipulation. In that Stipulation, the MIEC agreed that Ameren Missouri had a right to recover the solar rebate costs in rates. As the previous section of this brief makes abundantly clear, Ameren Missouri's current rates allowed it to already "recover in rates" all of the solar rebates at issue. But as the Stipulation provides, and as the Commission's Order approving it acknowledges, the solar rebate costs at issue "shall be considered for recovery" in rates.[25] It does not provide that the costs shall be recovered in a future rate case. The signatories to the stipulation agreed "not to object to Ameren Missouri's recovery in retail rates of prudently paid solar rebates."[26] Here, Ameren Missouri has already recovered the solar rebate costs in rates. Nothing prevents any party from objecting to multiple recoveries of the solar rebate costs.

Ameren Missouri cites footnote 7 of the Stipulation, which obviously was intended to address a situation where the solar rebate costs had not already been recovered from ratepayers. To read that footnote as Ameren Missouri does would be to forbid the signatories from objecting to recovery of the costs a second or third time in subsequent rate cases. Clearly the Stipulation as a whole contemplated the parties' understanding that Ameren Missouri would recover solar rebate costs from ratepayers once, and only once.

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[25] Stipulation, paragraph 7(d), page 5; Commission Order, page 2.

[26] Stipulation, paragraph 7(d), page 6.

Lastly, as the Commission is well aware, a number of complainants, including Noranda Aluminum, Inc., brought a complaint against Ameren Missouri in Case No. EC-2014-0223. In that case, complainants argued that Ameren Missouri's electric rates were too high and were allowing Ameren Missouri to consistently overearn. In response, among other things, Ameren Missouri argued that no rate decrease was warranted because it had incurred substantial costs of solar rebates that had been deferred and so were not reflected in its reported earnings.[27] The Commission denied rate relief to the complainants in that case. It did so in part on the fact that Ameren Missouri had paid the subject solar rebates which, had they been included in the calculation of revenue, would have lessened Ameren Missouri's overearnings.[28] It seems particularly inappropriate to deny the MIEC the opportunity to present this issue to the Commission after Ameren Missouri has already used those solar rebate costs in part to defeat a rate decrease complaint.

4. <u>Conclusion as To Deferred Costs</u>

Deferred solar rebate costs, vegetation management costs, pre-MEEIA costs, and Fukushima study costs were incurred during periods when Ameren Missouri was overearning by significant amounts. It would be unreasonable and unjust to make tomorrow's ratepayers pay more than just and reasonable rates so that Ameren Missouri can expand its already bloated earnings.

B. <u>Vegetation and Infrastructure Inspection Trackers</u>

In 2008, the Commission established rules for vegetation management and infrastructure inspections with which electric utilities had to comply. Due to the lack of historical cost experience for Ameren Missouri in complying with these new rules, the Commission allowed

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[27] *See* Ameren Missouri Initial Post Hearing Brief in Case No. ER-2014-0223, p. 19.

[28] *See* Report & Order, paragraph 24, p. 13, in Case No. ER-2014-0223.

these expenses to be eligible for a cost tracker.[29] The vegetation management rules required that rural circuits be trimmed every six years and urban cycles be trimmed every four years.[30] Currently, Ameren Missouri has achieved a complete cycle trim of all circuits on the Ameren Missouri system.

Ameren Missouri began compliance with these rules in January 2008, approximately six months earlier than the rules were approved by the Commission.[31] Through the true-up period in this rate case (December 2014), Ameren Missouri has seven years of cost experience and therefore has enough cost experience to establish a reasonable level of expense for rate making purposes. Quite simply, vegetation management and infrastructure expenses do not represent a large percentage of Ameren Missouri's operating expenses and the variations from rate case levels of those expenses are even smaller. Vegetation management costs represent approximately 2.8% and infrastructure inspections represent .3% of Ameren Missouri's operation and maintenance expenses.[32]

The Commission in its Order in Case No. ER-2012-0166 stated on page 107 the following: "However, as the Commission has indicated in previous rate cases, it does not intend for this tracker to become permanent."[33] Trackers merely allow one aspect of a utility's operations to be measured during a period of time when all other relevant factors are not considered. They are single-issue ratemaking mechanisms. Costs incurred through trackers do not have to meet the extraordinary standard for deferral accounting; trackers are merely a

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[29] Meyer Direct, Ex. 513, p. 22, ll. 7-17.

[30] *Id*.

[31] *Id*.

[32] Meyer Direct, Ex. 513, p. 22, ll. 18 -21; Meyer Surrebuttal, Ex. 514, p. 31, ll. 9-21 .

[33] Meyer Surrebuttal, Ex. 514, p. 22, ll. 4-13.

mechanism to track any cost difference between rate cases. These trackers have served their initial purpose and now need to be discontinued; they are not and should not be permanent.

In the event that the Commission does not discontinue these trackers, the MIEC proposes that the proper level of annual expense for vegetation management costs is $54 million and the proper level of annual expense for infrastructure inspections should be $5.8 million.[34] Ameren Missouri recommends that vegetation management expenses should be set at $56 million and infrastructure inspections should be set at $6.4 million.[35] These figures are the levels of expense incurred through the true-up period in this case.[36]

The MIEC, Staff and OPC all propose levels of expense based on multiple years averages. Multiple year averages are used frequently to normalize a level of expense for ratemaking purposes. Ameren Missouri proposes the level based on what was spent at the end of the true-up period. The use of a multiple year average is appropriate and should be adopted in this case. Merely seeking what was last expensed does not meet the standards for normalizing an expense, as that expense could either be too high or low. The level of annual expense for vegetation management activities has fluctuated over the years. The interaction between trimming rural verses urban routes can influence the level of costs. Therefore, a multiple year average is appropriate and should be adopted, as proposed by MIEC, Staff and OPC.

C. <u>Storm Tracker</u>

In Ameren Missouri's last rate case, the Commission approved a cost tracker for major storms. Prior to that rate case, Ameren Missouri would file Accounting Authority Orders (AAO's) to recover extraordinary major storm costs when they occurred. In fact, in the

[34] Meyer Surrebuttal, Ex. 514, p. 20, ll. 10-11.

[35] Meyer Surrebuttal, Ex. 514, p. 20, ll. 2-7.

[36] *Id*.

Commission's Report and Order in Case No. ER-2012-0166, the Commission stated the following:

> 4. The Commission has frequently approved such AAOs and has allowed Ameren Missouri to recover its extraordinary storm recovery costs through an AAO and subsequent five year amortizations. In fact, the company's current revenue requirement contains four separate amortizations related to extraordinary storm restoration costs.
> 5. The current system has allowed Ameren Missouri to recover all of its major storm recovery costs in recent years.[37]

The past recovery of major storm costs has worked well for Ameren Missouri and has been supported by ratepayers. There is no need to change the way major storm costs are recovered by allowing a storm tracker.[38] A tracker allows for every dollar of recovery regardless of the nature of the storm event and whether it was extraordinary. Furthermore, if the granting of a tracker precludes a party from arguing against cost recovery because of excess earnings, then the tracker should be discontinued on that basis as well. Ameren Missouri has failed to demonstrate why the past practice of filing AAOs for major storm cost recovery has deprived it of the opportunity to earn a fair and reasonable rate of return. Ameren Missouri does not need guaranteed recovery of any deviation of major storm expenses. For these reasons the storm tracker should be discontinued.

D. Noranda AAO - Recovery of the Noranda AAO Would Constitute Illegal Retroactive Ratemaking

Ameren Missouri proposes to recover the alleged "lost fixed costs" authorized for deferral in Case No. EO-2012-0027 in its revenue requirement in this case. These deferred costs represent that portion of Ameren Missouri's revenue shortfall that it claimed were fixed costs associated with the January 2009 ice storm that interrupted service to Noranda. Ameren

[37] Meyer Surrebuttal, Ex. 514, p. 23, ll. 12-28 (referring to page 94 of the Report & Order).

[38] Meyer Surrebuttal, Ex. 514, p. 23, ll. 5-11.

Missouri is not attempting to collect "lost fixed costs," but is attempting to recover unrealized profits by collecting ungenerated revenues. Ameren Missouri has historically collected revenues to recover all of its costs, and has reported positive earnings through the period from June, 2007 through September, 2014. If Ameren Missouri did not recover all of its costs, it could not have reported positive earnings, and the effect of its proposal is to seek a guaranteed recovery of a specific level of profit contrary to the lawful Missouri regulatory process.[39] By this proposal, Ameren Missouri would charge current ratepayers for costs associated with "ungenerated" revenue for prior periods years earlier.

Granting Ameren Missouri recovery for its ungenerated revenue violates the rule against retroactive ratemaking. Retroactive ratemaking is "the setting of rates which permit a utility to recover past losses … under a rate that did not perfectly match expenses plus rate-of-return with the rate actually established," and it is legally prohibited. *UCCM*[40]; *see Bd. of Pub. Util. Comm'rs v. New York Tel. Co.*, 271 U.S. 23, 31 (1926) ("If there is no return, or if the amount is less than a reasonable return, the company must bear the loss. Past losses cannot be used to enhance the value of the property"). Ameren Missouri seeks to accomplish what the *UCCM* Court prohibited, namely retroactive ratemaking: "To permit [it] to collect additional amounts simply because [it] had additional past expenses not covered … is retroactive rate making[.]"[41] In fact, increasing future customers' rates to compensate for past losses triggers customers' due process rights. *UCCM*.[42]

[39] Meyer Direct, Ex. 513, p. 16, ll. 10-24.

[40] 585 S.W.2d at 59.

[41] *Id.*

[42] *Id.* (The Commission may not "redetermine rates already established and paid without depriving the utility (*or the customer if the rates were originally too low*) of his property without due process.") (emphasis added).

Our Supreme Court addressed a similar situation in *UCCM.* There, after this Commission changed a rule regarding the FAC's calculation, the utilities went several months without collecting the extra rates owed under the FAC. This Commission imposed an order to collect the additional amount as a surcharge to future ratepayers. The Supreme Court ordered the monies refunded as illegally collected because not only the FAC charge itself was illegal but the surcharge also constituted "an [a]dditional recovery to that which had been allowed under the rates in force during the relevant period. The result was to require consumers to pay monies which should not have been paid."[43]

Likewise, Ameren Missouri argues that there is a period during which it recovered less than it was actually owed and seeks to recover that amount from future ratepayers. Effectively, Ameren Missouri wants to force future customers to pay the same surcharge that the Supreme Court ruled in *UCCM*[44] was illegally collected and that had to be refunded to ratepayers.[45] Recovery of a deferred cost cannot lawfully be permitted to allow a utility to recover "ungenerated revenues." Therefore, this Commission should deny the proposed recovery.

E. <u>Return On Equity</u>

1. <u>Introduction</u>

The costs of capital for Ameren Missouri and other electrical utilities are currently at historically low levels.[46] Since Ameren Missouri's last rate case when the Commission authorized a 9.8 percent return on equity ("ROE"), utility stock prices have increased and

[43] *See id.* pp. 58 - 59.

[44] *See id.*

[45] *See id.* ("The utilities have no vested right to or legitimate expectation in monies collected in this manner. To permit them to keep these monies would be a windfall to them and would leave their customers without a remedy for recovery of this unlawfully collected surcharge.")

[46] Gorman Surrebuttal, Ex. 512, p. 5, ll. 8 – 9.

dividend yields have declined, while growth rates have been relatively stable.[47] In the same period, utility bond yields have declined.[48] All of these factors point to one conclusion: Ameren Missouri's costs of capital have declined since the last rate case. The ROE authorized in this case should reflect that decline.

In addition, Ameren Missouri's investment risk has decreased since its last rate case due to favorable regulatory mechanisms in Missouri, and the elimination of affiliate risk associated with Ameren Corporation's divestiture of its merchant generation assets.[49] Consequently, Ameren Missouri's authorized ROE should decline to reflect this lower investment risk.

A careful analysis of independent market evidence shows that Ameren Missouri's current market cost of equity is within the range of 9.0 percent to 9.6 percent. An ROE within this range would balance the interests of ratepayers and the company by giving ratepayers the benefit of today's historically low capital costs while providing the company with fair compensation and access to the capital needed to fund its infrastructure investments.

Four witnesses provided testimony on the issue of Ameren Missouri's current market cost of equity. Three of the witnesses recommended returns on equity reasonably consistent with one another, while Ameren Missouri's witness provided an estimate that was a clear outlier. The non-Ameren witnesses' ROE recommendations range from approximately 9.0 percent to 9.6 percent. Ameren Missouri's ROE recommendation is a range of 10.2 percent to 10.6 percent, with a midpoint estimate of 10.4 percent. The witnesses' recommendations in this proceeding are outlined in the table below.

[47] Gorman Surrebuttal, Ex. 512, p. 7, ll. 7 – 14; Tr. p. 1269, ll. 3 – 4.

[48] Gorman Surrebuttal, Ex. 512, p. 6, l. 11 – p. 7, l. 6, and Table 1.

[49] Gorman Direct, Ex. 510, p. 7, l. 12 – p. 10, l. 2; Tr. p. 1138, l. 19 – p. 1139, l. 15.

Recommended Return on Equity			
Witness	**Return on Equity Range**	**Point Estimate**	**Cite**
Ameren Witness Hevert	10.2% - 10.6%	10.4%	Hevert Surrebuttal at 47
MIEC Witness Gorman	9.0% - 9.6%	9.3%	Gorman Direct at 2
Staff Witness Murray	9.0% - 9.5%	9.25%	Staff Report at 46
OPC Witness Schafer	8.7% - 9.2%	9.0%	Schafer Direct at 3

The preponderance of the evidence in this case demonstrates that Ameren Missouri's current market cost of equity falls in the range of 9.0 percent to 9.6 percent. This range encompasses most of the witnesses' findings and recommendations on ROE in this proceeding. Moreover, when the flaws and biases in Ameren Missouri witness Hevert's methodology are corrected, his studies also support an ROE within this range.[50]

2. Decline in Capital Market Costs Since Ameren Missouri's Last Rate Case

A material and verifiable decline in capital market costs has occurred since Ameren Missouri's last rate case in which the Commission authorized an ROE of 9.8 percent. Utility stock prices have increased and dividend yields have declined from 4.2 percent to 3.7 percent, while growth rates have been relatively stable.[51] These objective utility stock metrics reveal that market forces have driven up stock prices and thereby reduced utilities' cost of capital.[52] In addition, utility bond yields have decreased by 0.20 percent to 0.30 percent since Ameren

[50] Gorman Rebuttal, Ex. 511, p. 3, Table 1.

[51] Gorman Surrebuttal Ex. 512, p. 7, ll. 1-17; Tr. p. 1268, l. 23 – p. 1269, l. 13..

[52] Gorman Surrebuttal, Ex. 512, p. 9, ll. 7-11.

Missouri's last rate case.[53] This decline in observable capital market costs is objective evidence that Ameren Missouri's cost of equity today is lower than it was in its last rate case.

In response to questions from Chairman Kenney, MIEC witness Gorman explained the impact of higher stock prices, lower dividends, and stable growth rates on the cost of capital:

> "Stock prices can increase if there's a significant increase in the expected growth outlook for that stock. So the cash flow outlooks could increase. [In that case] the discount rate or the cost of capital may not change. **But that's not the case here.** Growth has increased a little bit, [as explained in] my testimony, relative to the last case, but not much. Dividend yields have gone down quite a bit.
>
> **Because the price of stock has gone up and other parameters of the stock have not significantly changed, that's a clear indication that investors have reduced their required cost of capital which has bid up the stock price.** So [investors are] willing to pay more for stock for the cash flows expected to be produced from that stock."[54]

In other words, investors today expect a lower return on their investment in Ameren Missouri's and other utilities' stock than at the time of the last rate case. Those lowered expectations are demonstrated by investors' willingness to pay more (as reflected in higher stock prices) for less (as reflected in lower dividend yields and a comparable growth outlook). It follows that the return Ameren Missouri needs to attract investors is lower in this case than it was in the last rate case. The ROE authorized in this case should reflect these facts.

In support of his assertion that Ameren Missouri's ROE should be set at 10.4 percent in this case, Ameren Missouri witness Hevert contends that because Treasury bond yields have increased since the last rate case, the company's cost of equity cannot be lower.[55] While there has been a slight increase in Treasury bond yields from their recent unusually low rates, this fact in no way refutes all of the other market evidence (utility stock prices, utility stock dividend rates

[53] Gorman Surrebuttal, Ex 512, p. 6, Table 1 and p. 7, ll. 1 - 2.

[54] Tr. p. 1268, l. 23 – p. 1269, l. 13 (emphasis added).

[55] Hevert Direct, Ex. 16, p. 41, ll. 1 – 12; Tr. p. 1154, ll. 8 – 15.

and utility bond yields) of a decline in capital market costs. At the time of Ameren Missouri's past few rate cases, Treasury bond yields were heavily impacted by Federal Reserve policy. The impact of this policy has dissipated in this case.[56] For this reason, Treasury bond yields should not be used to gauge the change in capital market costs. Although it is one aspect of the cost of capital, the recent increase in Treasury bond yields does not accurately reflect trends in the overall capital market environment. As MIEC witness Gorman noted, Treasury bond yields were so unusually low in the last rate case, he eliminated the CAPM analysis (which is heavily impacted by Treasury bond yield) when measuring Ameren Missouri's market cost of equity.[57] In the current case, Treasury bond yields have increased to more normal levels, and the CAPM cost of equity now falls within Gorman's recommended ROE range.[58] At their current levels, Treasury bond yields support the finding of an ROE in the range of 9.0 percent to 9.6 percent in this case. So although Treasury bond yields have increased from unreasonably low levels in the last rate case to a more reasonable and normal level in this case, this increase does not support the conclusion that Ameren Missouri's cost of common equity has increased.

It should also be noted that Hevert's discussion of "interest rates" in his Direct, Rebuttal and Surrebuttal testimony is misleading in that he focuses *solely* on Treasury bond yields.[59] He fails to even mention that public utility bond yields have declined by approximately 37 basis points since Ameren Missouri's last rate case.[60] The decline in utility bond interest rates is shown in the following table[61]:

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[56] Gorman Rebuttal, Ex. 511, p. 20, ll. 5 – 24.

[57] Tr. p. 1296, l. 13 – p. 1297, l. 15.

[58] Tr. p. 1297, ll. 12 – 15.

[59] Hevert Direct, Ex. 16, p. 41, ll. 1 -12; Hevert Rebuttal, Ex. 17, p. 6, l. 11 – p. 7, l. 2; Hevert Surrebuttal, Ex. 18, p. 7, ll. 1 – 10.

[60] Gorman Surrebuttal, Ex. 511, p. 7, ll. 1 – 2.

[61] Gorman Surrebuttal, Ex. 511, p. 6, Table 1.

Public Utility Bond Yields

Description	Surrebuttal Testimony[1]	Direct Testimony[2]	Case No. ER-2012-0166[3]
"A" Rated	3.90%	4.13%	4.27%
"Baa" Rated	4.63%	4.71%	5.01%
13 Week Period Ending	1/23/2015	11/7/2014	6/15/2012

Sources:
[1]Schedule MPG-SR-2.
[2]Schedule MPG-14, page 1 filed with Gorman direct testimony.
[3]Case ER-2012-0166, Schedule MPG-14, page 1.

As this table shows, interest rates declined even further between the filing of direct and surrebuttal testimony in this case.[62] This decline in interest rates alone supports a reduction in Ameren Missouri's authorized ROE of 9.8 percent to at least 9.4 percent.[63]

Ameren Missouri witness Hevert also testified that that utility stock prices are not "increasing," citing a dip in stock prices during the period from January 29 through February 27, 2015.[64] This testimony is a both misleading and irrelevant. The relevant inquiry here is not whether stock prices declined during the brief period cited by Hevert; instead, the Commission should consider whether utility stock prices are higher now than they were in Ameren Missouri's last rate case. While utility stock prices were driven up significantly through January 2015 and declined from those high levels by February 2015, that fact tells the Commission nothing about how the cost of equity now compares to cost of equity at the time of the last rate case. Moreover,

[62] Gorman Surrebuttal, Ex. 511, p. 7, ll. 4 – 6.

[63] Gorman Surrebuttal, Ex. 511, p. 7, ll. 3 – 4.

[64] Tr. p. 1152, l. 22 – p. 1153, l. 4.

prevailing utility stock prices are currently *higher* than the stock prices used by all of the expert witnesses in this case in their DCF studies to measure Ameren Missouri's cost of equity.[65] As MIEC witness Gorman explained, the stock prices used in the DCF study included in his Direct Testimony "weren't biased by those run up in prices in January and February."[66] Gorman's DCF analysis—which was based on stock prices that were not affected by the run up in prices and subsequent decline noted by Hevert, and which were actually *lower* than current stock prices—shows a decline in Ameren Missouri's cost of capital since the last rate case.[67] Moreover, a comparison between the data included in Hevert's testimony in this case and his testimony in the last rate case clearly indicates that utility stock dividend yields have *declined* since the last rate case, which further supports a finding of a lower cost of capital.[68]

Hevert's misleading assertion about a dip in stock prices during a one-month period, and his unwarranted focus on Treasury bond yields, prove nothing about Ameren Missouri's current cost of capital. The evidence in this case concerning utility stock prices, utility stock dividend yields and utility bond yields supports the finding that Ameren Missouri's cost of equity is significantly lower than it was in the last case. As Gorman's analyses indicate, the current market cost of capital supports an ROE for Ameren Missouri in the range of 9.0 percent to 9.6 percent, and specifically supports Gorman's recommended ROE of 9.4 percent.[69]

[65] Tr. p. 1288, l. 12 – p. 1289, l. 18.

[66] Tr. p. 1289, ll. 16 – 18.

[67] Tr. p. 1288, ll. 12 – 25 and p. 1289, ll. 1 – 4.

[68] Tr. p. 1178, l. 2 – p. 1180, l. 18 and p. 1181, ll. 11 – 22.

[69] Tr. p. 1269, ll. 6 – 13.

3. **Ameren Missouri's Investment Risk Has Decreased Since Its Last Rate Case**

Credit rating agencies found the Commission's rate order to be constructive in Ameren Missouri's last rate case.[70] In that order, Ameren Missouri was awarded several regulatory mechanisms that supported its credit standing and investment outlook.[71] Since the order was issued in the last rate case, Ameren Corporation divested itself of its merchant generating affiliate. This affiliate, though owned by Ameren Corporation, created increased investment risk for all of Ameren Corporation's subsidiaries, including Ameren Missouri.[72] Shortly after Ameren Corporation divested itself of the merchant generating affiliate, Ameren Missouri's bond rating was increased by both Standard & Poor's and Moody's. The sale of this high risk merchant generation company along with the resulting improvement in Ameren Missouri's bond rating are clear evidence that Ameren Missouri's investment risk today is lower than it was in its last rate case.[73] As Chairman Kenney stated, and Ameren Missouri witness Hevert agreed, "Generally speaking, when we're setting the ROE, the value of that number is ultimately a statement about the risk of the company."[74] Because its investment risk has declined, the Commission should award Ameren Missouri a lower ROE in this case, compared to that awarded in the last case.

4. **All Reasonable Market Cost of Equity Estimates Support a Finding that the Current Market Cost of Equity for Ameren Missouri is in the Range of 9.0 percent to 9.6 percent**

The only witness in this proceeding who recommended an ROE outside the range of 9.0 percent to 9.6 percent, was Ameren Missouri witness Hevert. However, Hevert's market cost of

[70] Gorman Direct, Ex. 510, p. 9, ll. 13 – 15.

[71] Gorman Direct, Ex. 510, p. 9, ll. 23 – 26.

[72] Tr. p. 1138, ll. 19 – 25 and p. 1139, ll. 2 – 20.

[73] *See* Tr. p. 1139, ll. 3 – 15.

[74] Tr, p. 1146, ll. 1 – 3.

equity studies contain significant flaws and biases, which overstated his market return estimate. When corrected, Hevert's DCF and risk premium studies support an ROE in the range of 9.0 percent to 9.6 percent.[75]

5. Constant Growth DCF

Ameren Missouri witness Hevert's recommended ROE of 10.4 percent is partly based on his DCF studies. Hevert performed both a constant growth and a multi-stage growth DCF study. Hevert's constant growth DCF study reflected low, mean and high growth rate estimates. Hevert's mean and high DCF growth rate estimates were 5.67 percent and 6.96 percent, respectively.[76] As explained by MIEC witness Gorman, the high DCF result produced by Hevert in his constant growth DCF analysis simply was not credible. The growth rate used to develop the high-end growth rate (6.96 percent) was nearly 1.5 times the expected long-term sustainable growth of the U.S. economy, and indeed was higher than the growth rate that was projected by any consensus equity analyst for the proxy group companies.[77] It is not reasonable to assume that a utility company's stock will grow at a rate that exceeds the growth of the economy in which it operates.[78] This high-end growth rate DCF analysis is simply not credible, and overstates a reasonable estimate of Ameren Missouri's current cost of equity. Excluding his high-end growth rate estimate, Hevert's DCF studies support an ROE in the range of 8.5 percent to 9.6 percent for Ameren Missouri in this case.[79]

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[75] Gorman Rebuttal, Ex. 511, p. 2, l. 20 – p. 3, Table 1.

[76] Gorman Rebuttal, Ex. 511, Schedule MPG-R-1

[77] Gorman Rebuttal, Ex. 511, p. 4, ll. 2 – 12.

[78] Gorman Rebuttal, Ex. 511, p. 5, ll. 10 – 12.

[79] Gorman Rebuttal, Ex. 511, p. 6, ll. 12 – 14.

6. Multi-Stage Growth DCF

Hevert's multi-stage growth DCF analysis produced results of 9.93 percent to 10.13 percent. However, there were material flaws in the inputs and structure of Hevert's multi-stage growth DCF study.

The long-term sustainable growth rate included in Hevert's analysis is not reasonable. Specifically, Hevert used a GDP growth forecast as long-term sustainable growth rate, but this forecast significantly exceeds independent market participants' current outlooks for U.S. GDP growth.[80]

In addition, Hevert erroneously accelerated cash flows in his multi-stage growth DCF model by assuming investors will receive four quarters of dividend payments after owning the stock for only two quarters.[81] This flawed assumption was included in each year of the DCF forecast, and significantly accelerated dividend payments relative to the stock purchase date. For obvious reasons, this assumption does not reflect reality, and produces an inaccurate and inflated DCF return estimate.

A second erroneous assumption included in Hevert's analysis concerns the dividend payout ratio. A company's "dividend payout ratio" represents the percentage of earnings paid to shareholders as dividends. Hevert assumed that at the transitional stage in his multi-stage analysis, the dividend payout ratio will increase, notwithstanding the fact that payout ratios for the proxy group companies are projected to be at their steady-state rate.[82] By including this

[80] Gorman Rebuttal, Ex. 511, p. 6, ll. 17 – 20 and p. 8, ll. 1-7, Table 2.

[81] Gorman Surrebuttal, Ex. 512, p. 12, ll. 5 – 15.

[82] Gorman Rebuttal, Ex. 511, p. 8, l. 11 – p. 9, l. 3.

increase in payout ratio in his analysis, Hevert overstates dividend payments, resulting in an overstated DCF return estimate.[83]

By leaving all other parameters used by Hevert intact and correcting for these three deficiencies, Hevert's multi-stage growth DCF model produces an ROE in the range of 8.70 percent to 8.90 percent[84] This is *below* the range of 9.0 percent to 9.6 percent found reasonable by all the other parties.

7. <u>CAPM</u>

Ameren Missouri's recommended ROE is also based in part on Hevert's Capital Asset Pricing Model ("CAPM"). Hevert's model produced an overstated estimate of ROE due to his use of an unreasonably high market risk premium. Hevert used market risk premiums of 10.02 percent to 9.28 percent in his CAPM studies.[85] These are significantly higher than historical actual achieved market risk premiums, which have ranged from 6.2 percent to 7.3 percent.[86] Hevert's market risk premiums were also based on flawed DCF studies, which included expected market growth estimates of approximately 11.49 and 10.62 percent that cannot be sustained indefinitely as required by this DCF model.[87] Corrections to Hevert's market risk premiums and use of his other CAPM parameters produce an estimated ROE for Ameren Missouri in the range of 8.80 percent to 9.52 percent.[88]

8. <u>Bond Yield Plus Risk Premium</u>

Ameren Missouri's recommended ROE of 10.4 percent is also founded on a flawed risk premium analysis included in Hevert's testimony. As MIEC witness Gorman explains in his

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[83] Gorman Rebuttal, Ex. 511, p. 9, l. 17 – p. 10, l. 6.

[84] Gorman Rebuttal, Ex. 511, p. 10, ll. 1 – 4.

[85] Gorman Rebuttal, Ex. 511, p. 12, l. 9.

[86] Gorman Direct, Ex. 510, p. 37, l. 13 – 14. .

[87] Gorman Rebuttal, Ex. 511, p. 12, ll. 1 – 4.

[88] Gorman Rebuttal, Ex. 511, p. 13, ll. 8 – 14.

testimony, Hevert's analysis is based on the view that "there is a simplistic inverse relationship between risk premiums and interest rates."[89] This conclusion is not supported by academic research.[90] By focusing solely on interest rates, Hevert failed to properly measure the way in which the market gauges equity risk premiums. While interest rates are one factor that can impact the level of equity risk premiums, they are not the only factor. It is well-established that relative changes in the perceived investment risk of an equity security versus that of a bond security also cause changes to market risk premiums.[91]

Correcting Hevert's bond yield risk premium study to reflect the market's current risk and valuation assessments of equity and debt securities results in an equity risk premium above Treasury bond yields in the range of 4.41 percent to 6.28 percent.[92] This is significantly lower than the risk premiums of 7.53 percent and 8.43 percent used by Hevert in his analysis. These more reasonable utility equity risk premium estimates, in combination with current observable utility bond yields and projected Treasury bond yields, produce a utility risk premium return estimate of approximately 8.00 percent.[93]

9. <u>The Company's Claim that Market Return Models Are Not Producing Reliable Return Estimates is Without Merit</u>

Hevert criticized the findings of the other experts in this case, and biased his own findings upward, based on a plethora of unsupported justifications for setting aside the results of market-based models. These unsupported justifications focus on three areas: (1) utility stock

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[89] Gorman Rebuttal, Ex. 511, p. 14, ll. 5 – 6.

[90] Gorman Rebuttal, Ex. 511, p. 14, l. 6.

[91] Gorman Rebuttal, Ex. 511, p. 14, ll. 5 – 10, citing, "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," Robert S. Harris and Felicia C. Marston, *Journal of Applied Finance,* Vol. 11, No. 1, 2001 and "The Risk Premium Approach to Measuring a Utility's Cost of Equity," Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *Financial Management,* Spring 1985.

[92] Gorman Direct, Ex. 510, p. 31, l. 2.

[93] Gorman Rebuttal, Ex. 511, p. 3, l. 20.

price to earnings ("P/E") ratios, which Hevert inaccurately characterizes as being "elevated";[94] (2) market volatility,[95] which has much less impact than Hevert's testimony indicates; and (3) average authorized returns on equity issued by other regulatory commissions,[96] which as Gorman's testimony demonstrates, are overstated by Hevert's analysis.

Hevert asserts that utility stock P/E ratios are at "unusually high, and likely unsustainable levels," and that because of these high P/E ratios, the DCF analyses of Gorman and the other expert witnesses are unreliable.[97] But as Gorman explains, Hevert arrives at his conclusion that P/E ratios are elevated by comparing current stock prices to historical earnings per share, rather than to expected future earnings per share. Hevert's analysis fails to take into account that many electric companies, including Ameren Missouri, are experiencing stronger near-term earnings outlooks now than they did in the past.[98] Hevert's P/E ratio analysis ignores the strong improvement in expected earnings of utility companies over the next three to five years. If forward-looking earnings are taken into account, the P/E ratio of the proxy group's prevailing stock price is actually *below* the historical normal.[99] Current prices relative to projected earnings suggest that P/E ratios will eventually decline to a more sustained level as utilities' earnings increase with their elevated capital spending programs.[100] Given this outlook, the multi-stage growth DCF model can accurately estimate a DCF return for Ameren in this case, because it can reflect the expectation of high growth followed by a more sustainable growth rate.[101] Contrary to

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[94] Hevert Rebuttal, Ex. 17, p. 28, ll. 11-13.

[95] Hevert Direct, Ex. 16, p. 40, ll. 6 – 12.

[96] Hevert Rebuttal, Ex. 17, p. 4, ll. 4 – 11.

[97] Hevert Rebuttal, Ex. 17, p. 5, ll. 9 – 12.

[98] Gorman Surrebuttal, Ex. 512, p. 8, l. 7 – p. 9, l. 2.

[99] Gorman Surrebuttal, Ex. 512, p. 8, ll. 15-19.

[100] Gorman Surrebuttal, Ex. 512, p. 8, ll. 12 – 24.

[101] Tr. p. 1299, ll. 10 – 18.

Hevert's assertions, the current P/E ratios of the proxy group companies are not grounds for rejecting Gorman's DCF estimates in this case.

Further, Gorman demonstrated that the constant growth DCF model in this case is based on logical data input parameters and produces logical results.[102] This evidence was not rebutted by Ameren Missouri's witness, nor was Gorman cross-examined on this conclusion. The constant growth DCF model is not designed to capture a declining P/E ratio while multi-stage growth DCF model is designed to capture these non-constant growth factors. Both models in this case produce reasonably consistent and reliable results.[103] For these reasons, contrary to Hevert's assertions, the current P/E ratios of the proxy group companies are not grounds for rejecting any witness', including Gorman's, DCF estimates in this case.

Hevert's allegations concerning changing volatility were not shown to detract from the usefulness and accuracy of the other expert witnesses' market-based ROE estimates.[104] Market volatility is a risk of investing in utility stocks. Therefore, the market volatility will impact the valuation of a stock and the outlook for expected valuation parameters such as dividend yield and growth rates. Further, the volatility will be reasonably captured within market-based DCF studies.[105] However, Hevert's testimony ignores the clear market evidence that investors regard utility investments as low-risk stable investments. Instead Hevert lumped utility investments in with higher-risk general corporate investments to give the false impression that utility investments are not regarded as low-risk.[106] Hevert's assertions about the market's perception of utility investment risk is not supported.

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[102] Gorman Direct, Ex. 510, p. 18, l. 3 – p. 19, l. 9.

[103] Gorman Direct, Ex. 510, p. 26, ll. 5 – 12.

[104] Gorman Rebuttal, Ex. 511, p. 17, ll. 13 – 17.

[105] Gorman Rebuttal, Ex. 511, p. 17, l. 3 – p. 18, l. 25; Gorman Surrebuttal, Ex. 512, p. 8, l. 1 – p. 9, l. 24.

[106] Gorman Rebuttal, Ex. 511, p. 17, ll. 10 – 17.

In his rebuttal testimony, Hevert states that 10.0 percent is the "approximate median authorized ROE for vertically integrated electric utilities since January 2013."[107] He repeatedly cites 10.0 percent as a benchmark for evaluating the reasonableness of his ROE estimates, as well as the reasonableness of the other witnesses' analyses.[108] He argues that any estimates below this benchmark should be given little if any weight. But Gorman's Schedule MPG-SR-1 provides a more thorough analysis of the recently authorized ROEs. Gorman's analysis demonstrates that 9.63 percent, not 10.0 percent, is the average of the most relevant recently authorized ROEs.

In his analysis, Gorman takes into consideration all electric utilities – both vertically integrated as well as distribution companies—with comparable levels of investment risk. This increases the number of data points included in his analysis, which, in general, has the effect of decreasing the impact of any anomalous results.[109] The electric utility companies selected by Gorman for consideration all have similar credit ratings.[110] As Ameren Missouri witness Hevert confirmed, a company's credit rating reflects investment risk.[111] Gorman eliminated from consideration those commission determinations of ROE that were not the result of litigation, but were instead determined through settlement, or were simply carried over from prior cases.[112] This ensures that all of the results considered by Gorman were based on evidence concerning market factors.

[107] Hevert Rebuttal, Ex. 17, p. 93, l. 19 – p. 94, l. 1.

[108] *See, e.g.,* Hevert Rebuttal, Ex. 17, p. 93, ll. 19 – 20; p. 101, ll. 17 -18.

[109] *See* Tr. p. 1130, ll. 7 – 11; p. 1300, l. 24 – p. 1302, l. 11.

[110] Gorman Surrebuttal, Ex. 512, Schedule MPG-SR-1, p. 1.

[111] Tr. p. 1121, ll. 20 – 23.

[112] Gorman Surrebuttal, Ex. 512, p. 3, l. 14 – p. 4, l. 15; Tr. pp. 1275 – 1276.

Gorman's analysis indicates that ROEs authorized in 2014 for all electric companies, where this issue was fully litigated, ranged from 9.17 to 10.20 with an average of 9.63 percent.[113] This average is generally consistent with Gorman's estimated ROE range of 9.0 percent to 9.6 percent.[114] This does not mean, however, that any estimate of the current market cost of equity below 9.63 percent is inaccurate or unreasonable. Average commission-authorized returns are simply one data point to consider in determining the reasonableness of the witnesses' testimony in this case.[115] They should not be used to exclude from consideration reasonable analyses that use observable and verifiable market-based evidence to estimate Ameren Missouri's current market cost of equity.[116]

Hevert's assertion that the market-based ROE estimates provided by Gorman are not reliable is simply without merit. The Commission should award Ameren Missouri an ROE in the range of 9.0 percent to 9.6 percent in this proceeding. An ROE in this range is supported by competent and substantial evidence in this case, including the testimony of MIEC witness Gorman who recommends the Commission authorize an ROE of 9.4 percent for Ameren Missouri in this case. Moreover, when corrected as described above, the testimony of Ameren Missouri witness Hevert also supports an ROE in this range. The evidence in this case is clear that Ameren Missouri's cost of equity has declined since its last rate case. The company's ratepayers should receive the benefit of this lower cost through a lower authorized return on equity in this case.

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[113] Gorman Surrebuttal, Ex. 512, Schedule MPG-SR-1, p. 1.

[114] Tr. p. 1276, l. 24 – p. 1277, l. 18.

[115] Gorman Surrebuttal, Ex. 512, p. 4, ll. 19 – 22.

[116] Gorman Surrebuttal, Ex. 512, p. 4, l. 22 – p. 5, l. 2.

F. **Noranda Load**

Aluminum smelters use large amounts of power every hour of the year. The Noranda smelter has historically used as much power as the city of Springfield, Missouri. Noranda is Ameren Missouri's single largest customer representing about ten percent of Ameren Missouri's sales. Under normal operations, Noranda consistently uses about 485 MW of power with an approximate 98% load factor. A 98% load factor means that during 98% of the hours in a year, Noranda uses about 485 MW of power.

In its direct testimony, Ameren Missouri proposed that Noranda's normalized revenues should be calculated based off of 4,198,453 MWhs of usage per year. That figure is typical for Noranda's normal operations. Subsequent to the direct filing, Noranda began experiencing an abnormal level of pot failures to the point where Noranda used up all of its spare pots. While it rebuilt the failed pots, it had to temporarily curtail production until all pots were back on line. As a consequence, it has used an abnormally lower amount of electricity while this process continued. But the undisputed evidence is that Noranda will be at normal production prior to the time that rates from this case become effective.

As a result of this temporary reduced power consumption, Ameren Missouri proposed to reduce the normalized level of revenues for Noranda. In its rebuttal testimony, Ameren Missouri proposed to lower Noranda's annual level of consumption from 4.2 million MWhs to 3.8 million MWhs, even though it acknowledged that Noranda expected to be at normal production before rates are established in this case. This would represent an approximate 9.5 percent decrease in usage from the level Ameren Missouri proposed in its direct case. Reducing the number of billing units of Ameren Missouri's largest customer by 9.5 percent over the amount that customer is likely to consume while rates are in effect has a significant negative impact on ratepayers.

In Ameren Missouri's surrebuttal testimony, it advanced even more arguments. There, Ameren Missouri witness Steven Wills proposes three alternatives from which the Commission may choose to calculate Noranda's billing units, and thus revenues. Mr. Wills proposes the following levels of usage for Noranda:

10 Year average usage levels: 3,989,934 MWhs

3 Year average usage levels: 3,828,667 MWhs

Test Year Updated/True-Up: 4,139,345 MWhs

None of these proposals has merit. The 10 year average includes the effects of the ice storm, something that Ameren Missouri agrees was an extraordinary event. The three year and test year figures includes the anomaly of the recent pot failures. Noranda's load should reflect normal operating conditions and should not be reduced for extraordinary events. Under normal operating conditions, Noranda will consume 4,198,453 MWhs per year. It is undisputed that Noranda's normalized load is the amount originally proposed by Ameren Missouri in its direct testimony.

Noranda's response to discovery clearly states that the load will be restored prior to the Operation of Law date in this rate case. To establish Noranda's load at anything lower than its normalized level of approximately 4.2 million MWhs will unjustifiably increase the profits of Ameren Missouri at the expense of ratepayers. Except for the ice storm and the abnormal level of pot failures which coincidentally occurred as a result of the ice storm, Noranda has operated at a 98% load factor, consuming approximately 485 MWhs on an hourly basis. Noranda's load should be 4,198,453 MWhs.

G. Income Tax Allocation Issues

1. Accumulated Deferred Income Tax/Affiliate Transaction Rule

The Test Year Accumulated Deferred Income Tax ("ADIT") balance to be included within rate base should not be Ameren Missouri's overstated ADIT estimates for net operating loss deferred tax asset carry-forwards. Rather, the ADIT balance should be as calculated by Mr. Brosch. The facts and amounts associated with this issue are not disputed. Rather, the Commission is asked to determine whether the "consolidated group" or the "stand-alone" method of calculating Ameren Missouri's Net Operating Loss Carryforward ("NOLC") deferred tax asset should be employed. This determination can only be made in favor of MIEC's proposal, as a matter of equity to ratepayers and to comply with the Commission's own affiliated interest rule that prohibits a regulated electric utility from subsidizing non-regulated affiliated operations.

By way of background, ADIT balances are assets or liabilities that represent cumulative amounts of additional income taxes that are estimated to become either receivable or payable in future periods. These ADIT amounts result from differences between book accounting and income-tax accounting regarding the timing of revenue or expense recognition.[117] Normally, ADIT amounts in the aggregate serve to reduce utility rate base, recognizing the ability of capital-intensive electric utilities to utilize accelerated and bonus tax depreciation and other tax preferences to defer the cash payment of income taxes. However, when bonus depreciation and other tax deductions grow so large as to push taxable income negative, the utility must record an offsetting deferred tax asset for the NOLC amounts that reduce the utility's tax deferral opportunity.

[117] Brosch Direct, Ex. 501, p. 13, ll. 5-8.

There are two ways to calculate NOLC-related ADIT balances: the "consolidated group" method and the "stand-alone" method.[118] The different methods lead to different NOLC deferred tax asset balances here: the consolidated and stand-alone methods result in carry-forward losses of $215.7 million and $69.7 million, respectively.[119] Whichever way they are calculated, the NOLC balances, and resulting deferred tax asset balances, are normally included in rate base by regulators so as to properly quantify the net amount of investor-supplied capital to support rate-base assets.[120] In this case, Ameren Missouri has improperly calculated its NOLC deferred tax asset balance based on an allocation of Ameren Corporation's consolidated group return carry-forward losses, so as to ***overstate*** its rate base by $50.9 million.

The legal issue here arises from the Commission's policy that prevents regulated utilities, like Ameren Missouri, from using unreasonable affiliate arrangements that disadvantage the regulated utility and its ratepayers. Mr. Brosch explained that utility holding companies are free to invest in both regulated and non-regulated subsidiaries and to structure cost allocation and affiliate-transaction arrangements between the controlled subsidiaries that may be more beneficial to shareholders than to ratepayers. He noted that "[i]n particular, Ameren Corporation's TAA [Tax Allocation Agreement] produces extremely adverse consequences for Ameren Missouri's ratepayers in 2013 by crowding out the utility's taxable income in that year with tax losses from Ameren Corporation's divestiture of its merchant generation and energy marketing subsidiaries." Mr. Brosch added that it is entirely reasonable for the Commission to employ affiliate-transaction policies and safeguards that protect against unreasonable utility

[118] Brosch Surrebuttal, Ex. 502, p. 6, ll. 5-7.

[119] Warren Rebuttal, Ex. 48, p. 26, Table VII at column 4; Brosch Surrebuttal, Ex. 502, p. 17 at Expanded James Warren Table VI. These are pretax amounts, prior to application of income tax rates to determine the resulting deferred tax asset amount. *See* MLB-10, p. 2 at row 2014, columns (2) and (4)

[120] Brosch Direct, Ex. 501, p. 15, ll. 12-17.

transactions with affiliates.[121] Ameren Corporation's TAA requires the allocation of consolidated annual income-tax responsibility among the members of Ameren's consolidated tax group and defines the amounts of income tax that are recorded on the utility's books.[122] There is no dispute that Ameren's TAA is a contract among corporate affiliates or that the TAA is now producing financial outcomes not favorable to Ameren's regulated operations.[123] Ameren Missouri's own witness, Mr. Warren, agrees that Ameren Missouri and its ratepayers will be better off currently, and for each of the last two years, by applying the stand-alone method.[124] He also agrees that, by using the consolidated method, Ameren Missouri seeks to attribute greater cumulative tax losses to its ratepayers than would be attributed under the stand-alone method.[125] He agrees that if the carry-forward loss were calculated on a stand-alone basis, then it would offset less of Ameren Missouri's ADIT liability balance, thus producing a lower rate base.[126]

Indeed, the Commission has recognized the risks created by utility-affiliate contracts. Under 4 CSR 240-20.015(2)(A), a regulated electrical corporation cannot provide a financial advantage to an affiliated entity (the "Affiliated Transaction Rule"). The Commission has specified the purpose for this rule:

> This rule is intended to prevent regulated utilities from subsidizing their nonregulated operations.… The rule and its effective enforcement will provide the public the assurance that their rates are not adversely impacted by the utilities' nonregulated activities.

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[121] Brosch Surrebuttal, Ex. 502, p. 7.

[122] Brosch Surrebuttal, Ex. 502, p. 6.

[123] Warren Rebuttal, Ex. 48, p. 27, ll. 20-22: "It was only as of the end of 2013 that Ameren Missouri on a consolidated basis finally shifted into a slightly disadvantageous position."

[124] Warren Rebuttal, Ex. 48, p. 11, ll. 1-3.

[125] Tr. p. 334, ll. 13-22.

[126] Tr. p. 350, l. 18 – p. 351, l. 2.

Ameren Missouri proposes to include overstated NOL carryforward ADIT balances based on its preferred "consolidated group" method of allocating carry-forward losses to Ameren Missouri. Use of that method would impose higher electric rates on ratepayers because rate base will be $50.9 million higher than results from calculating such NOLC amounts based solely upon Ameren Missouri's cumulated tax losses on a stand-alone basis. The Commission's Affiliated Transaction Rule does not permit this result. Applying 4 CSR 240-20.015(2)(A) to the undisputed facts demonstrates that Ameren Missouri cannot use its consolidated-group NOLC calculation approach to overstate rate base.

First, the ADIT net operating loss carry-forward deferred tax amount is clearly an ***asset***.[127] Ameren Missouri's witness, Mr. Warren, agrees that the amount at issue is a deferred tax asset.[128] There is no dispute that it is appropriate to include NOLC deferred tax assets to increase the rate base.[129] What is disputed is whether this asset can be made larger simply because of Ameren's TAA, which is clearly an affiliate arrangement subject to the Rule.

Second, Ameren Missouri proposes to use its consolidated-group method to ***transfer*** the value it derives from filing a consolidated tax return and allocating tax losses broadly among its subsidiaries, in a manner that improperly benefits Ameren's non-regulated affiliates.[130] Starting in 2013, Ameren Missouri's stand-alone taxable income grew substantially; at the same time, Ameren Corporation's divestiture transactions generated substantial tax losses.[131] These

[127] Brosch Direct, Ex. 501, p. 13, ll. 5-8.

[128] Tr. p. 350, ll. 1-7.

[129] Brosch Surrebuttal, Ex. 502, p. 5, l. 22. Alternatively, even if the Commission does not agree that the carry-forward loss is an asset, it should still find that the prohibition in 4 CSR 240-20.015 is not limited to assets. Rather, the Affiliate Transaction Rule applies to a broader set of items than just assets. This broader application serves the purpose of the Rule, which is to assure the public that a utility's non-regulated activities will not adversely impact their rates. Tr. p. 382, l. 18 – p. 383, l. 3; Brosch Surrebuttal, Ex. 502, p. 13, l. 5 – p. 14, l. 8.

[130] Warren Rebuttal, Ex. 48, p. 18, ll. 13-17; Brosch Surrebuttal, Ex. 502, p. 18, ll. 1-10.

[131] Brosch Direct, Ex. 501, p. 25, l. 16 – p. 26, l. 2.

undisputed facts can be observed in Ameren Missouri's response to MIEC 27.4,[132] which shows in columns 1 and 2 that Ameren Missouri's "stand alone" annual and cumulative tax losses are much lower than the allocated tax losses that are allocated to Ameren Missouri under the Company's unreasonable TAA (see columns 3 and 4). By the Company's own calculations in columns 5 and 6 of this response, Rate Base is overstated by $50.9 million using the "consolidated group" approach favored by Ameren Missouri. In other words, Ameren Missouri seeks in 2013 and 2014 to transfer the value it derives from realization of Ameren Missouri's stand-alone taxable income (its deferred tax asset) to other members of the Ameren consolidated group and to the detriment of Ameren Missouri's ratepayers. That this is the case is undisputed.

Third, the effect of the Company's preferred consolidated-group NOLC deferred-tax asset quantification method is that Ameren Missouri will provide income-tax consolidation benefits to the Ameren group and, in exchange, be compensated at a value ***below*** the fully-distributed cost to Ameren Missouri, as reflected on its stand-alone tax returns. MIEC's approach, in contrast, would attribute the full amount of Ameren Missouri's cumulative taxable revenues, fully-distributed costs, and resulting taxable income on a stand-alone basis to the utility's operations, as contemplated in the Commission's Rule.

Moving beyond the legal issue, equity for Missouri ratepayers also demands acceptance of the stand-alone method of determining NOLC tax-asset balances. There is a clear reason why Ameren Missouri is now harmed by the holding company's TAA and the consolidated-group allocation method required therein. Ameren Corporation engaged in a one-time restructuring transaction in 2013 to divest its holdings in Ameren Generating Company, Ameren Energy Resources, EEI, Inc., and Ameren Energy Marketing Company, primarily to Dynegy, Inc. As

[132] Brosch Surrebuttal, Ex. 502, Schedule MLB-10.

explained by MIEC witness Mr. Brosch, this restructuring transaction contributed to massive income tax losses on Ameren Corporation's consolidated tax return in 2013. That restructuring, under the consolidated-group approach to NOLC allocation, precluded Ameren Missouri from offsetting its stand-alone tax losses from 2008 through 2010 against its own sizable taxable income in 2013.[133] Ameren Missouri's taxable income, reflecting its own fully distributed costs, would have served to reduce the utility's cumulative tax losses in 2013 if not for the massive tax losses arising from Ameren Corporation's restructuring transaction. The Commission's Affiliate Transaction Rule, as well as equity for ratepayers, precludes this unreasonable allocation of Ameren Corporation's income-tax consequences.

Ameren Missouri should not be allowed to include in rate base any net operating loss or tax credit carry-forward balances that exceed the amount that would result from calculating Ameren Missouri's income taxes on a stand-alone basis in each applicable year through calendar 2014.[134] That limitation is essential to prevent Ameren Missouri's rate base from being overstated due to its affiliates' income-tax losses.[135] The Commission's Affiliate Transaction Rule and sound regulatory policy are designed to prevent such affiliate abuse and resulting disadvantages for ratepayers.[136]

Moreover, there is nothing inherently unfair about implementing the stand-alone method in this instance.[137] Utility holding companies are free to invest in regulated and non-regulated subsidiaries, and allocate revenues and costs among those affiliates for tax and other

[133] *Id.* p. 8.

[134] Brosch Direct, Ex. 501, p. 26, ll. 14-18.

[135] Brosch Direct, Ex. 501, p. 26, ll. 18-21.

[136] Tr. p. 382, l. 18 – p. 383, l. 3.

[137] Brosch Surrebuttal, Ex. 502, p. 14, l. 9 – p. 15, l. 2.

advantages.[138] However, the Commission has recognized the need to protect ratepayers from the adverse rate impacts that arise when a regulated affiliate subsidizes a non-regulated affiliate.[139] Implementation of the stand-alone method here protects the ratepayers from just such a subsidy.

The Commission has the power to avoid this subsidy. Nothing prevents the Commission from applying the stand-alone method to determine ADIT and Ameren Missouri's rate base even though the Ameren Corporation employed the consolidated-group method for its tax calculations.[140] The right result will turn on the Commission's implementation of its rules and affiliated interest policy.[141] The Commission's policy is clear: regulated utilities cannot subsidize their non-regulated affiliates' businesses to the detriment of ratepayers.[142] The public interest requires the Commission to apply the stand-alone method for the purpose of determining Ameren Missouri's NOLC deferred tax asset to be included in rate base.

2. <u>Section 199 Domestic Production Income Tax Deduction</u>

The other income tax issue in this matter involves the domestic production income tax deduction. The Commission should require Ameren Missouri to retain the historical treatment of income tax expense adjustments for Internal Revenue Code section 199 domestic production deductions, so as to continue use of a stand-alone calculation method that has been used in previous Ameren Missouri rate cases.

Under 26 U.S.C. § 199, taxpayers are allowed a tax deduction as a percentage of income earned from Qualified Production Activities Income.[143] It is a tax incentive that Congress

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[138] Brosch Surrebuttal, Ex. 502, p. 7, ll. 1-18.

[139] 4 CSR 240-20.015.

[140] Tr. p. 346, ll. 3-18.

[141] Tr. p. 352, ll. 3-7.

[142] 4 CSR 240-20.015; Tr. p. 384, ll. 10-24.

[143] Brosch Direct, Ex. 501, p. 9, ll. 11-12.

provides to manufacturers.[144] The domestic production deduction ("DPD") has historically been calculated for ratemaking purposes[145] by reflecting the forward-looking level of revenues after implementing the proposed rate increase and all test-year adjusted operating expenses allocated to the production part of Ameren Missouri's business, including Ameren Missouri's tax deductions, without consideration of the prior year's net operating loss.[146] Ameren Missouri now seeks to also consider prior-year net operating losses.[147]

As with the stand-alone versus consolidated method for calculating ADIT carry-forward, the general question is whether Ameren Missouri should continue to calculate the DPD reflecting only Ameren Missouri's test-year financial inputs. Here, the specific question is whether Ameren Missouri can apply a new methodology, inserting prior year tax losses, when determining the DPD that will reduce taxable income and thereby increase Ameren Missouri's revenue requirement (and ratepayers' rates). The Commission should not let it do so.

Ameren Missouri's customers benefit from a larger DPD.[148] The DPD has been consistently calculated in rate cases based upon pro-forma (adjusted) test-year operating revenues and expenses, including Ameren Missouri's proposed rate increase amount, and is therefore entirely forward looking. This means that the DPD amount has been calculated for the rate-effective period and in a manner that ignores Ameren Missouri's NOLC amounts.[149] Ameren Missouri's witness, Mr. Warren, agrees that the approach proposed here by Ameren

[144] Warren Rebuttal, Ex. 48, p. 31, l. 7.

[145] Tr. p. 408, l. 20 – p. 409, l. 7.

[146] Tr. p. 395, l. 17 – p. 396, l. 2.

[147] Tr. p. 371, ll. 6-12.

[148] Tr. p. 342, l. 21 – p. 343, l. 1.

[149] Brosch Surrebuttal, Ex. 502, p. 20-21.

Missouri is a departure from its past practice.[150] With Ameren Missouri's traditional approach, the Commission can determine whether there is sufficient taxable income to claim a deduction; and, there has consistently been a deduction.[151] There is also a degree of predictability in the formula and clarity for ratepayers.

Ameren Missouri's new approach completely eliminates any DPD tax deduction for ratemaking purposes by inserting large cumulative NOLC amounts within the calculation of the deduction. This outcome is inappropriate and inconsistent with the methods used to calculate the DPD and should be rejected.

Mr. Brosch provided a calculation template for the DPD in his Direct Testimony, at Schedule MLB-4, page 2, resulting in a DPD amount of $36.8 million. This approach to DPD determination, using no NOLC inputs, is consistent with previous Ameren Missouri rate cases and should be used as the template to recalculate the final true-up amounts in this rate case. Mr. Brosch explained that he did not believe any change to this approach is necessary.[152] However, he also recognized that "…it is nearly impossible to predict whether or not Ameren Missouri will have positive future taxable income when new rates are in effect, particularly given the recent tendency of Congress to take up important tax policies such as bonus depreciation very late in the year, for application retroactively." He then provided a revised DPD calculation "for use only in test years where significant NOLC amounts, calculated on a stand-alone basis are expected to persist" within his Schedule MLB-4 REVISED. These alternative calculations support a much lower DPD of $7.9 million.[153] Thus, if the Commission is convinced that Ameren Missouri's proposed change to now include NOLC amounts in calculating the deduction

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[150] Tr. p. 341, ll. 2-5.

[151] Tr. p. 396, ll. 2-4.

[152] Brosch Surrebuttal, Ex. 502, p. 22.

[153] Tr. p. 345, ll. 6-14; Brosch Surrebuttal, Ex. 502, Revised MLB-4.

is warranted, it could use Mr. Brosch's alternative approach as the template for true-up calculation of the tax deduction.

Applying Ameren Missouri's traditional approach to the DPD results in a higher DPD tax deduction, which justifies a reduced revenue requirement not dependent upon estimation of NOLC inputs. The traditional approach also provides clarity and predictability. The Commission should therefore reject Ameren Missouri's proposed change in DPD calculation methodology.

II. CLASS COST OF SERVICE, REVENUE ALLOCATION AND RATE DESIGN

In this section of the brief, MIEC sets forth its position with respect to the appropriate methodology to determine class cost of service, the appropriate revenue allocation and rate design.

A. Class Cost of Service Studies

1. Allocation of Generation Demand-Related Costs

The single most important decision in performing a class cost of service study is to determine the method used to allocate the fixed, or demand-related, costs associated with generation plant investment. In this case, as in several prior cases, both Ameren Missouri and MIEC have used the Average & Excess – 4 Non-Coincident Peak ("A&E-4NCP") method. As explained by MIEC witness Brubaker:[154]

> **Q WHAT IS THE A&E METHOD?**
>
> A The A&E method is one of a family of methods which incorporates a consideration of both the maximum rate of use (demand) and the duration of use (energy). As the name implies, A&E makes a conceptual split of the system into an "average" component and an "excess" component. The "average" demand is simply the total kWh usage divided by the total number of hours in the year. This is the amount of capacity that would be required to produce the energy if it were taken at the same demand rate each hour. The

[154] Brubaker Direct, Ex. 503, p. 25, l. 16 - p. 26, l. 7.

> system "excess" demand is the difference between the system peak demand and the system average demand.
> Under the A&E method, the average demand is allocated to classes in proportion to their average demand (energy usage). The difference between the system average demand and the system peak(s) is then allocated to customer classes on the basis of a measure that represents their "peaking" or variability in usage.[1] [Footnote omitted.]

Ameren Missouri witness William Davis gave a similar explanation in his testimony:[155]

> **Q. From a generation perspective, what were the considerations associated with the Company's election to utilize the A&E demand allocation methodology for production plant in this case?**
>
> A. Two major factors associated with generation capacity planning prompted the use of the A&E demand cost allocation methodology. Generally, system peak demands and, to a somewhat lesser extent, excess customer demands, are the motivating factors which influence the amount of capacity the Company must add to its generation system to provide for its customers' maximum demands. However, the type of capacity (base, intermediate, or peaking) that the Company must add is not dictated by maximum customer demand alone, but also by the annual energy, or kilowatt-hours, that will be required to be generated by such capacity, i.e., the generation unit's utilization factor. A cost allocation methodology that gives weight to both a) class peak demands and b) class energy consumption (average demands) is required to properly address both of the above considerations associated with capacity planning. The A&E methodology gives weight to both of these considerations by its inclusion of both average class demands, which are kilowatt-hours divided by total hours in the year (8,760), and the excess NCP demands of each class. As indicated earlier, the Company's A&E cost allocation study used both the 4 NCP and average class demands in the determination of class excess demands.

The A&E-4NCP method supported by Ameren Missouri and MIEC has been repeatedly endorsed by this Commission over a number of cases. For example, in Case No. ER-2010-0036, the Commission selected the A&E method as the most appropriate one, and it generally described its reasoning at pp. 84-86 of its May 28, 2010 Order.

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155 Davis Direct, Ex. 7, p. 10, l. 21 - p. 11, l. 12.

2. Allocation of Off-System Sales Revenue

A major sub-issue in the allocation of generation function costs is the allocation of off-system sales revenue. Both Ameren Missouri and MIEC allocated the revenues from off-system sales on the basis of the customer class energy allocation factor. Off-system sales are revenues that are produced by the sale of electricity that is available, but not needed at the time of the sale to serve retail customer load. These sales are non-firm, and no capacity is reserved for, or committed to, these sales. The major expense incurred in supporting off-system sales is fuel cost (and, to a limited extent, purchased energy), all of which expenses are allocated to customer classes using the customer class energy allocation factor. For these reasons, it is appropriate to allocate the revenues from off-system sales to customer classes using the class energy allocation factor. Ameren Missouri witness Warwick testified about this as follows:[156]

> A. The Company and MIEC allocated off-system sales revenues based on their respective energy (kWh) allocators, which is consistent with the method approved in File No. ER-2010-0036, where the Commission states, "the Commission finds that AmerenUE's class cost of service study, modified to allocate revenues from off-system sales on the basis of class energy requirements, is the most reliable of the submitted studies."

The Commission made a similar finding in Kansas City Power & Light Company Case No. ER-2006-0314 when considering this very issue. Although this consideration was in the context of a jurisdictional allocation, the Commission affirmatively found that an allocation on energy was the appropriate policy. The Commission stated as follows in the Report and Order in Case No. ER-2006-0314, issued December 21, 2006, at p. 39:

> The only costs assigned to non-firm off-system sales is the fuel and purchased power costs – the variable costs – hence the appropriateness of using the energy allocator. This is consistent with the way KCPL itself allocates the costs relating to the energy portion of firm capacity contracts – using the energy allocator. The reason is simple – the energy allocator is used to allocate variable costs of fuel

[156] Warwick Amended Rebuttal, Ex. 50, p. 13, ll. 1-6.

and purchased power costs relating to retail sales. Using the same rationale, the energy allocator is equally appropriate to use as the allocation factor for both energy of firm (as KCPL does) and non-firm off-system sales.

3. Classification and Allocation of Production Function Non-Fuel O&M Expenses

Another issue in the allocation of production function costs is the classification and allocation of production non-fuel operation and maintenance expenses. MIEC witness Brubaker explained the rationale for the classification.[157] The issue centers around certain non-labor costs in the generation operations cost category and the generation maintenance category. Mr. Brubaker testified as follows:[158]

> A It is my position that the vast majority of these costs do not vary in any appreciable way with the number of kilowatthours generated, but occur primarily as a function of the existence of the plants, the hours of operation and the passage of time. In fact, Ameren Missouri schedules the maintenance on its coal and nuclear generation units on a "passage of time" basis, not on a "kWh generated" basis. I believe the most appropriate approach is to classify all of the generation O&M expense other than fuel and purchased power as a fixed cost. This is sometimes referred as the "expenses follow plant" basis. It is the basis that generally has been used in Missouri for classification and allocation of these costs.

Notably, both Staff and OPC adopted this same approach and categorized all production non-fuel O&M expenses as fixed, and then allocated those costs based on each parties' respective fixed production plant allocator.[159]

4. Determination of Income Taxes

The issue of the determination of income taxes associated with individual classes is also important. As Mr. Brubaker explained, Ameren Missouri includes in its present rate cost of service study the full amount of income taxes that it would pay if it received the full amount of

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[157] Brubaker Direct, Ex. 503, p. 32, l. 11 - p. 33, l. 11.

[158] *Id*. at p. 33, ll. 1-11.

[159] Warrick Amended Rebuttal, Ex. 50, p. 8, ll. 18-20.

its requested rate increase.[160] As a result, income taxes at present rates are overstated by roughly $100 million. Second, Ameren Missouri allocates income taxes on rate base rather than on the taxable income of the individual customer classes. If all customer classes were producing the same rate of return, allocating income taxes on rate base or on class taxable income would produce the same result. However, all classes are not producing the same rate of return at present rates and would not be doing so under the rates proposed by any party in this case. Since income tax is determined by taxable income, a clear and correct presentation of the cost of service study results at present rates requires that income taxes be calculated based on class taxable income. Mr. Brubaker's class cost of service study that is shown in Schedule MEB-COS-4 to Ex. 503 does exactly that.

MIEC notes that the Staff, in its cost of service studies, calculates income taxes for each customer class based on its current taxable income.[161]

5. <u>Conclusion</u>

The Commission should adopt the A&E-4NCP methodology. It clearly is the most appropriate, and is in the mainstream of allocation methodologies for electric utilities. In contrast, OPC's average and peak allocation has been repeatedly rejected by this and other commissions, and should continue to be rejected in this case. Similarly, the Commission Staff studies, which are outside the mainstream, conflict with prior Commission rulings and do not reliably reflect cost-causation, should be rejected.

The Commission should also adopt MIEC's positions an off-system sales, non-fuel production O&M expense and income taxes, and Ameren Missouri's position on all other cost allocation issues.

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[160] Brubaker Direct, Ex. 503, p. 30, l. 10 - p. 31, l. 13.

[161] Warwick Amended Rebuttal, Ex. 50, p. 14, ll. 6-7.

B. Revenue Allocation and Rate Design

The result of MIEC's cost of service study, in terms of rates of return at present rates, and revenue neutral adjustments to move all classes to cost of service at present rates are shown in the table below.

MIEC CLASS COST OF SERVICE STUDY
RESULTS AT PRESENT RATES

Rate Class	Rate of Return[1] (1)	Revenue Neutral Adjustments to Move to Cost of Service at Present Rates (2)
Residential	4.65%	5.6%
Small GS	6.79%	(4.2%)
Large GS/Small Primary	7.82%	(7.7%)
Large Primary (LPS)	5.93%	(0.5%)
Large Transmission (LTS)	4.64%	4.2%
Lighting	5.81%	0
Total	5.81%	0

(1) Brubaker Direct, Ex. 503, Schedule MEB-COS-4
(2) p. 7 of Ex. 977

In light of the results of the class cost of service study, MIEC recommends (as do Ameren Missouri and the Commission Staff) that the Large Primary Service ("LPS") customer class receive the system average percentage increase awarded by the Commission in this case. MIEC recommends that each charge within the tariff (excluding the low-income surcharge and the MEEIA charge) receive this same percentage increase.

The details respecting the Large Transmission Service ("LTS") revenue allocation and rate design are addressed below in Section III of this brief. However, for purposes of maintaining the availability of the existing LTS rate for future use, MIEC recommends that each charge within the LTS tariff receive the same overall percentage increase as the LPS class.

C. Economic Development Tariff and Rider E

This Commission should not condition the use of the economic development rider to participation in the costs of the MEEIA program. First, for certain customers that requirement would appear to conflict with section 393.1075.7 by assigning costs to ratepayers who have opted out of MEEIA:

> Provided that the customer has notified the electric corporation that the customer elects not to participate in demand-side measures … <u>none of the costs of demand-side measures of an electric corporation … shall be assigned </u>to any account of any customer, including its affiliates and subsidiaries, meeting one or more of the following criteria[.] (emphasis added)

Second, that requirement would appear to be bad public policy in that the Economic Development rider is designed to attract loads or to maintain loads that are at risk. Increasing the cost for those customers runs counter to the purpose of the tariff. This is particularly true for customers who would not benefit from the MEEIA program.[162]

The Rider E issue is addressed in a March 5, 2015 Nonunanimous Stipulation that has received no objection. The Commission approved that Stipulation on March 15, 2015.

D. Transmission Costs for Self-Generated Power

This issue is simple and straightforward. Legally, for purposes of section 386.266.1, is power that Ameren Missouri produces with its power-generation equipment to serve its load "purchased power?" This question leads to sub-issues. If, as Ameren Missouri argues, all of its self-generated power is sold to MISO, is all of that power for off-system sales? Then, is all of the power that serves its load purchased power? Factually, does Ameren Missouri report its power production as if it is all for off-system sales? Does it report all of its fuel purchases as purchases for off-system sales? Does it report none of its fuel purchases as fuel for load? Does the tariff for MISO Schedule 26A (the bulk of the charges at issue) support Ameren Missouri's

[162] Brubaker Rebuttal, Ex. 504, p. 26, ll. 1 - 18.

position? The answer to all of these questions is "no." Because the answer to the first question in particular is no, then the MISO transmission charges at issue are not transportation costs of purchased power and **are** ineligible for surcharge through the FAC under section 386.266.1. They must be recovered as most of Ameren Missouri's costs are recovered, namely by building them into base rates in a rate case.

Missouri law is clear that utilities may not surcharge increased costs between rate cases unless the General Assembly expressly allows it. See *State ex rel. Utility Consumers Council of Missouri, Inc. v. Public Service Commission of Missouri ("UCCM")*:[163]

> It is for the legislature, not the PSC, to set the extent of the latter's jurisdiction. The mere fact that the commission has approved similar clauses in the past, or that other states permit them, is irrelevant if they are not permitted under our statute[.]

After *UCCM*, the Missouri General Assembly enacted section 386.266.1. It provides:

> Subject to the requirements of this section, any electrical corporation may make an application to the commission to approve rate schedules authorizing an interim energy charge, or periodic rate adjustments outside of general rate proceedings <u>to reflect increases and decreases in its prudently incurred fuel and purchased-power costs, including transportation</u>[.]

Therefore, a surcharge is allowed only to the extent that section 386.266.1 authorizes it. Notwithstanding Ameren Missouri's position here, both Ameren Missouri and this Commission have previously concluded that the statute does not allow all transmission charges to be surcharged.

During the rulemaking hearing to adopt the FAC rule under section 386.266.1, Ameren Missouri candidly admitted:

> FACs allow utilities to timely pass through the necessary costs … associated with obtaining the fuel needed to fire the generation that serves customers, as well as

[163] 585 S.W.2d 41, 54 (Mo. banc 1979).

> the costs associated with purchased power needed to supplement the energy and capacity available from the utility-owned generation.[164]

"This statement, which was made well after the Company's integration in MISO and the April 1, 2005 startup of the MISO Day 2 energy markets, clearly shows that the Company has previously recognized it serves its load from its own generating units and supplements this generation with power purchases."[165] Stated differently, purchased power is only that power needed to serve load that is in addition to the power that Ameren Missouri self-generates. This Commission recognized as much in *In re Kansas City Power & Light, Greater Missouri Operation*:

> 76. The Commission concludes that all transmission costs should not be included in GMO's adjustment clause because they are not included in section 386.266, RSMo. Supp. 2010, as a type of cost to be recovered through a fuel adjustment clause, they are inconsistent with the definitions of fuel and purchased power cost in 4 CSR 240-20.090(1)(B), and elsewhere, and they do not vary in a direct relationship with fuel or purchased power. With regard to the transmission costs specifically related to [off-system sales], however, those costs shall be allowed[.][166]

Ameren Missouri's position here is akin to GMO's, namely that all transmission charges may be surcharged.

A plain reading of section 386.266.1 supports Ameren Missouri's earlier interpretation and this Commission's interpretation in *In re Kansas City Power & Light, Greater Missouri Operation*. If all power provided to ratepayers is "purchased power," as Ameren Missouri now claims, then why would section 386.266 even allow a surcharge for fuel costs since ratepayers are served solely by purchased power? Ameren Missouri's current construction of the statute makes no sense. If Ameren Missouri's current construction were correct, the statute would have

164 Docket No. Ex-2006-0472 (comments of Union Electric Company d/b/a Ameren UE, September 7, 2006 at page 2) (emphasis added); Dauphinais Surrebuttal, Ex. 509, p. 9.

165 Dauphinais Surrebuttal, Ex. 509, p. 10.

166 Case No. ER-2010-0356, p. 218-219 (emphasis added).

simply allowed a surcharge of all increases in purchased-power costs and the costs to transmit purchased power.

Mr. Dauphinais recognized the absurdity of Ameren Missouri's position that it sells all self-generated power to MISO and buys it back to serve its load:

> If we ignore the fact the Company generates almost all the power it sells to its customers, and instead engage in the fiction that it sells all of its generated power to MISO as off-system sales and buys it back for its customers as purchased power:
>
> > The fuel and purchased power cost for power paid by customers would be equal to the wholesale market price for power -- not the Company's cost to produce power in its own generating units supplemented by occasional wholesale market purchases; and
> >
> > The entire output of the Company's generation facilities would be dedicated to the production of off-system sales -- not to serving the Company's customers.
>
> Under this scenario, the Company's accounting with the Commission would not assign any generation fuel costs to customers -- only purchased power costs would be assigned to customers. In addition, there would be grounds for the Commission to remove from the Company's rate base the entire net plant of the Company's generation facilities since those facilities would no longer be serving the Company's customers.
>
> Fn (Obviously, if this was done, the fuel expenses, O&M expenses and off-system sales revenues associated with the Company's generation facilities would also be removed from rates.)[167]

What Ameren Missouri regularly reports to this Commission in its numerous filings belies its argument here. Exhibits 524-528 are Ameren Missouri's last five FAC Surveillance Monitoring Reports. In each such report, on page 3-a, Ameren Missouri reports its fuel expense for native load separately from its fuel expense for off-system sales. On each such report the fuel expense for native load is significantly larger than the expense for off-system sales. Wouldn't all fuel costs be for off-system sales if Ameren Missouri were selling off-system all of its

[167] Dauphinais Surrebuttal, Ex. 509, p. 8, ll. 7-21 (including fn).

production? Likewise, its reported expense for purchased power for native load is far less than its fuel expense for native load. On Exhibit 524, for instance, the cost of fuel for native load is over $682 million. Yet the cost of purchased power for native load is merely $62 million. If Ameren Missouri were selling off-system its entire production of energy, it certainly would not be buying it back for one-tenth of just one component (fuel) of the cost to produce it. Ameren Missouri's own filings with this Commission expose its argument here for what it really is, namely an opportunistic attempt to sweep into the FAC far more than anyone, including Ameren Missouri, contemplated at the time section 386.266 was adopted and the FAC rule thereunder was implemented.

One of the arguments that Ameren Missouri makes is that the subject transmission charges have always flowed through the FAC and, thus, should continue to do so. First, it is undisputed that the key charge at issue here, the Schedule 26-A charge, did not begin to flow through the FAC until January 2012.[168] Second, as the Missouri Supreme Court cautioned in the *UCCM* case, past practice does not matter: "[i]t is for the legislature, not the PSC, to set the extent of the latter's jurisdiction. The mere fact that the commission has approved similar clauses in the past … is irrelevant if they are not permitted under our statute."[169]

Another argument that Ameren Missouri makes is that this Commission has already addressed this issue, finding in Ameren Missouri's favor, which decision was affirmed by the Court of Appeals. But this Commission has not addressed this issue and the Court of Appeals in fact said so:

> As a threshold issue, we must address the PSC's contention that Consumers failed to preserve these 'purchased power' issues for appeal. The PSC argues that Consumers should be barred from arguing the purchased power issues

[168] Haro testimony in ER-2012-0166, Tr. p. 1173, ll. 19-23 (Official Notice).

[169] 585 S.W.2d at 54.

> <u>because those issues were never presented to the PSC for consideration below</u>. We agree.[170]

The bulk of the transmission charges at issue are for MISO Schedule 26A. The language of the Schedule 26-A tariff does not support Ameren Missouri. The tariff for that Schedule, Exhibit 529, shows that the Schedule 26-A charges are for power flowing over transmission lines. Page 1 of Exhibit 529 provides that the rates for Schedule 26-A are for applicable "Monthly Net Actual Energy Withdrawals," which on page 2 of that exhibit are defined as including, among other things, the volume of energy flowing out of the transmission system. In short, Schedule 26-A is agnostic about whose power is transmitted. It does <u>not</u> create a charge for transmission of only <u>MISO's power</u> (assuming that MISO can take title to power) to Ameren Missouri or any other utility. Rather, it is merely a charge for transmission of power, which can and does include Ameren Missouri's self-generated power that is transmitted from its power generators to its load.

As explained below, transmission revenues (issue number 30(E)5) should be treated consistent with the Nonunanimous Stipulation approved by this Commission on March 19, 2015 and consistent with its decision on the above issue. Because of MIEC's position that transmission costs that are not incurred to transmit purchased power should be excluded in the FAC, Mr. Dauphinais in his direct testimony proposed to exclude all transmission revenue (Account 456.1) amounts from the FAC.[171]

However, Mr. Dauphinais in his surrebuttal testimony clarified that if the Commission concludes the transmission costs in dispute in this proceeding can be included in the Company's

[170] *Union Electric Company v. Public Service Commission*, 422 S.W.3d 358, 364 (Mo. App. 2014)(emphasis added).

[171] Dauphinais Direct, Ex. 508, p. 14, l. 17 – p. 15, l. 17.

FAC, MIEC would be agreeable to also including transmission revenues in the FAC.[172] Subsequent to Surrebuttal Testimony in this proceeding, the Company, Commission Staff and MIEC entered into a non-unanimous stipulation with respect to the disposition of the issue of whether or not transmission revenues should be included in the FAC (Non-Unanimous Stipulation and Agreement Regarding Class Kilowatt-Hours, Revenues and Billing Determinants, Net Based Energy Costs, and Fuel Adjustment Clause Tariff Sheets, March 5, 2015 or "Non-Unanimous NBEC Stipulation"). Under Paragraph 7 of the Non-Unanimous NBEC Stipulation, the Company, Commission Staff and MIEC agreed that, with respect to transmission revenues incurred under Account 456.1, if (i) the Commission does not decide that all transmission charges should be included in the FAC and (ii) the Commission also does not decide that all transmission charges other than those to transmit off-system sales should be included in the FAC, then all transmission revenues would be excluded from the FAC and would be recovered solely through base rates. As a result, under this non-unanimous stipulation, if the Commission agrees with MIEC that the transmission charges incurred to transmit the Company's self-generated power to its load should be excluded from the FAC, then all transmission revenues would also be excluded from the FAC. However, if the Commission decides against MIEC on this issue, then all transmission revenues would be included in the Company's FAC under the non-unanimous stipulation.

III. NORANDA RATE DESIGN

A. The Commission Has Authority to Determine Just and Reasonable Rates and Noranda Accepts and Supports Just and Reasonable Conditions on Such Rate Relief

Without rate relief, the New Madrid smelter is not viable. Rate relief is required now to provide the necessary cash flow to pay its bills in the normal course of business, to demonstrate

[172] Dauphinais Surrebuttal, Ex. 509, p. 12, ll. 14-20.

to the banks that it has a cost structure that will support the refinancing of its debt, and to provide a reasonable opportunity for the smelter to remain viable through the aluminum price cycle. The proposed rate relief, including the Nonunanimous Stipulation filed in this case on March 10, 2015, balances the needs of all parties. It supports the continued operation of the smelter and the maintenance of 850 jobs, provides a net benefit to other ratepayers, and recognizes the Commission's continuing authority to ensure that the net benefit continues to be provided and that Noranda does not obtain a windfall gain.

In its initial petition for rate relief in this case, Noranda proposed a rate that significantly improves the likelihood the smelter will remain viable, while also preserving the benefit that having Noranda on the Ameren system provides to other consumers. Similarly, the Nonunanimous Stipulation and Agreement which has support from representatives of all customer classes except the Lighting class[1], improves the likelihood of smelter viability while also preserving the benefit having Noranda remain on the system. Noranda believes the evidence presented in this case establishes the reasonableness of both of these rate proposals and shows that rate relief as supported by Noranda is critical to provide the liquidity necessary to support current daily operations, to allow Noranda to survive through this aluminum pricing cycle and, most importantly, to allow Noranda to refinance its debt when due in February of 2017 and February of 2019. Noranda believes the terms of the Nonunanimous Stipulation ensure that ratepayers benefit, protect against any potential unjust enrichment to Noranda, and recognizes this Commission's continuing jurisdiction and oversight over the rate design.

In its Report and Order in the complaint Case No. EC-2014-0224, the Commission stated that it "encourages the parties to continue to pursue negotiations on a compromise position as it could be considered in Ameren Missouri's current rate case, File No. ER-2014-0258". The

[1] The Lighting Class does not object to the Nonunanimous Stipulation.

Commission additionally stated in its Order Denying Applications for Rehearing "the parties are encouraged to continue to pursue negotiations on a compromise position that can be presented for consideration in the general rate case". In keeping with the Commission's orders, Noranda has negotiated for many months with consumer groups and other parties to find a compromise position that balances all interests, keeping in view the Commission's findings in the complaint case.

There is no objective bright line for what is or what is not the appropriate rate structure or term. At the same time, Noranda recognizes that the Commission may take into account other views and has the discretion to afford Noranda any rate relief that the Commission finds to be just and reasonable and in the public interest. In its testimony, Noranda notes that to the extent the Commission approves a rate higher than the rate Noranda proposed, the risk of the New Madrid smelter's failure increases at least proportionately. Likewise, as the term of a secure, sustainable rate structure is shortened, the risk grows that Noranda will be unable to refinance its debt and the New Madrid smelter will not be viable. Although Noranda strongly supports the compromise embodied in the Nonunanimous Stipulation, Noranda also still believes that the terms and conditions of its initial proposal would create a viable foundation for its success. But it is clear that denial of rate relief will result in the ultimate shutdown of the smelter.

B. Rate Relief for Noranda is In the Public Interest

The evidence is undisputed that Noranda's operation of the New Madrid smelter provides benefits to Ameren Missouri's ratepayers because Noranda pays a substantial amount of Ameren Missouri's fixed costs, amounts that will be borne by Ameren Missouri's other ratepayers should the smelter close. Even at a $34/MWh rate, Noranda would be contributing more than $20 million annually to cover fixed costs. That Noranda pays a substantial portion of fixed costs is indeed one of the many reasons that Ameren Missouri encouraged this Commission to allow it to serve Noranda. In its request to obtain a CCN to serve Noranda, Ameren Missouri represented:

> In summary, the evidence in this case will show that virtually every relevant public interest consideration mitigates strongly in favor of granting the requested CCN. All analyses show AmerenUE's cost will be lower with Noranda than without it; Noranda unquestionably needs AmerenUE's reliable, cost-based, regulated service; Noranda prefers AmerenUE's reliable, cost-based, regulated service, and Noranda's preference is indeed reflected in the State's public policy and customer preference, has been relied upon by this Commission in the past in any event; and finally, considerations relating to the economic development and prosperity of the region and the state show the public interest is promoted by granting this CCN. [173]

Significantly, at the time that this Commission approved the CCN for service to Noranda the market price for power, unlike now, was above the rate Noranda was to be charged, and yet the Commission still found that it was in the public interest to serve Noranda at a lower than market rate (but at its cost of service).[174] Additionally, as Union Electric noted above, it is likewise undisputed that Noranda's operations in New Madrid provide economic benefits to Noranda' employees, to Southeastern Missouri and to the State of Missouri.[175]

It is also undisputed that load retention discounts are appropriate, indeed regularly authorized by tariff, so long as the discounted rate: (1) is necessary to retain the load; and (2) is above the incremental cost to serve that load.[176] The evidence in this case is compelling that without rate relief, Noranda is unlikely to be able to refinance its debt coming due in 2017 and 2019, Noranda will have insufficient cash flow and liquidity, and will likely be forced to close

[173] Dauphinais testimony, Tr. p. 2798, l. 19 – p. 2799, l. 10, p. 2800, ll. 1-10, p. 2849, l. 24 – p. 2850, l. 13 (from Union Electric's prehearing brief in Case No. EA-2005-0180).

[174] Dauphinais testimony, Tr. p. 2842, l. 25 – p. 2844, l. 17.

[175] Haslag Direct and Surrebuttal, Exs. 606 and 607.

[176] Brubaker Direct, Ex. 503, p. 43, ll. 1-7; Tr. p. 2663, ll. 1-19.

the smelter.[177] The evidence is compelling that at a $34/MWh rate (or at any higher rate) Noranda is contributing to fixed costs (i.e. paying above the incremental cost to serve it).

Should the New Madrid smelter close, ratepayers will shoulder an extra $56 million per year once Ameren Missouri has its rates reset in its next rate case ($42/MWh - $28/MWh x 4 million MWhs in round numbers). However, between the time of closure and the time rates are reset, Ameren Missouri will lose between $40 million and $56 million per year, depending on whether "factor N" "revenues" in tariff sheet 72.4 include FAC revenues.[178] In short, it is in everyone's interest to keep the Noranda smelter open, even if it means that Noranda buys power at a discounted rate.

The only party to present witnesses opposing <u>any retail rate relief</u> for Noranda <u>for any period of time under any conditions</u> is Ameren Missouri. It is indeed ironic that Ameren Missouri will foist onto ratepayers its cost of opposition to Noranda as a rate case expense. That irony will be compounded when, as a possible result of Ameren Missouri's opposition, Noranda receives no relief and closes the smelter, causing Ameren Missouri to claim that the closure was an unexpected and extraordinary event triggering an AAO, thus compelling ratepayers to pick up between rate cases the entire $56 million per year of additional expense the closure causes.[179] Thus, ratepayers will pay more after Ameren Missouri's rates are rebased and will possibly pay more prior to rebasing, resulting in utterly no impact to Ameren Missouri. And ratepayers clearly would benefit if Noranda had received a discounted rate above incremental cost of service if that will keep the smelter open.

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[177] Smith Surrebuttal, Ex. 612, p. 4, ll. 1-12; Boyles Direct and Surrebuttal.

[178] Dauphinais testimony, Tr. p. 2842, l. 25 – p. 2844, l. 17, p. 2854, l. 8 – p. 2855, l. 1, and p. 2877, ll. 3-6.

[179] Dauphinais Testimony, Tr. p. 2877, l. 22 – p. 2878, l. 16. The MIEC does not mean to imply that any such AAO is lawful or reasonable.

C. <u>Noranda's Proposed Rate Would Benefit Ratepayers Because It Covers the Incremental Cost of Serving Noranda and Contributes to Ameren Missouri's Fixed Costs to the Benefit of All Ameren Missouri Ratepayers.</u>

During the hearing, the Commissioners and counsel, particularly counsel for the Commission Staff, frequently posed the following question of the experts on this issue: Is there a discounted rate for Noranda at which ratepayers are better off than if Noranda closes its smelter? The metric used to answer that question is the "incremental cost of power." The incremental cost of power is the avoided cost if Noranda were no longer served. The avoided costs include obvious things like the cost of energy, but also things like the cost of capacity, the cost of line losses in transmission, and other costs.[180] If that metric is less than what the power can be sold for to Noranda, then ratepayers are better off selling the power to Noranda. As stated by Staff Witness Sarah Kliethermes: "If you believe that without rate relief Noranda will close down, the Staff says, yes, something's better than nothing. Mitigate it as best you can."[181]

<u>Every witness answered this question in the affirmative</u>.[182] These witnesses (Brubaker, Dauphinais, Kliethermes, and Michels) disagreed only on what that calculated incremental cost was and for how long it was good. Their disagreements focused on how the cost was to be determined (using historical prices (Brubaker, Dauphinais and Kliethermes) or using forward market energy prices (Michels)). Those witnesses who used historical prices to determine incremental cost only differed on whether to use one, three, or four years of prices and whether to exclude the prices during the polar vortex anomaly. And for the calculations using forward energy prices, they disagreed on whether they should use forecasts over two years old or use

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[180] Dauphinais Direct, Ex. 508, p. 16, l. 4 – p. 17, l. 15.

[181] Kliethermes testimony, Tr. p. 3002, ll. 21 – 24.

[182] Brubaker (MIEC) testimony, Tr. p. 2654, 1. 3 – p. 2656, l. 9, p. 2683, ll. 2 – 23; Dauphinais (MIEC) testimony, Tr. p. 2792, l. 16 – p. 2794, l. 2; Kliethermes (Staff) testimony, Tr. p. 3002, ll. 8 – 24; Michels (Ameren Missouri) testimony, Tr. p. 2939, ll. 16 – 21, p. 2957, l. 2 – p. 2959, l. 3.

current forecasts.[183] But all of the experts agreed that the incremental cost of power, however calculated, would for a period of time likely be less than $34/MWh.

Mr. Dauphinais calculated the incremental cost of power based upon a three year normalization of historical costs, with removal of the polar vortex anomaly, as between $28.03/MWh and $29.39/MWh.[184] He used exactly the same method that Ameren Missouri, Staff and MIEC used to calculate a comparable metric, Ameren Missouri's FAC's net base energy costs (NBEC).[185] His opinion is that it is "highly likely" that the incremental cost of power will be below $34/MWh for the next 36 months.[186] He also opines that if Noranda closes its plant, the price that will be realized for off-system sales (OSS) will decline. That is because of supply and demand. The supply of energy will be the same, but the quantity demanded will decline significantly since Noranda represents more than ten percent of Ameren Missouri's sales.[187] Lower OSS prices are bad for ratepayers since they share in 95 percent of them and Ameren Missouri has significant OSS.[188] Since Ameren Missouri witness Michels suggested that forward market prices should be used rather than historical prices, Mr. Dauphinais, with the assistance of Mr. Phillips, calculated reasonable projections of incremental power costs using current expectations of forward energy prices. He calculated a future seven year average incremental cost of $33.84/MWh.[189] Although Dauphinais' testimony does not set out those incremental costs by year, Mr. Michels admitted that for the period June 2015 through May

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[183] Phillips Surrebuttal, Ex. 516, p. 8, ll. 17-22.

[184] Dauphinais testimony, Tr. p. 2790, ll. 16 – 21; Dauphinais Surrebuttal, Ex. 509, p. 13, ll. 4-14.

[185] *Id*.

[186] Dauphinais testimony, Tr. p. 2801, ll. 10 – 19.

[187] Dauphinais Direct, Ex. 508, p. 26, ll. 6 – 16, Tr. p. 2874, ll. 6-25; Phillips Surrebuttal, Ex. 516, p. 3, ll. 11-14.

[188] Dauphinais testimony, Tr. p. 2875, ll. 1 – 12.

[189] Dauphinais Surrebuttal, Ex. 509, p. 25, ll. 1 – 12.

2016, he calculated an incremental cost of power, using forward power prices, of $** **/MWh, and for the period June 2016 through May 2017, $** **/MWh.[190]

Commission Staff witness Sarah Kliethermes also calculated the incremental cost of power, and did so a number of different ways using historical cost information. She used staff's fuel run for a cost of $29/MWh at Noranda's meter.[191] Staff later modified that figure to $28.29/MWh based upon an updated fuel run.[192] She also offered the incremental cost found reasonable in case No. EC-2014-0024: $31.50/MWh.[193] Last, she listed a calculation using a twelve month period ending July 1, 2014 that included the full effects of the polar vortex. That figure was $35.88/MWh.[194] However, at trial, she was clear that in her opinion the incremental cost of power, or "breakeven" price, is $31.50:

> I actually did not do a full new calculation in this case, because in my opinion nothing really significant has changed with that calculation that the Commission found this summer, and I believe that's 31.50 at Noranda's meter.[195]

She later stated that the $31.50/MWh incremental cost is "a reasonable value for purposes of setting rates from case to case. As you know, we use historic test year information in developing rates."[196] MIEC disagrees with this calculation because it does not normalize for the polar vortex anomaly. Nevertheless, Noranda's proposal provides benefits to other customers even if this $31.50/MWh benchmark is used.

Matt Michels also weighed in on this issue. His opinion is that the Commission should not determine the incremental cost of power based upon historical information, but rather on

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[190] Michels testimony, Tr. p. 2946, ll. 6 – 18.

[191] S. Kliethermes Rebuttal, Ex. 221, p. 10, table 4.

[192] S. Kliethermes Surrebuttal, Ex. 222, Appendix 1-6 (not paginated).

[193] S. Kliethermes Rebuttal, Ex. 221, p. 10, table 4.

[194] *Id*.

[195] S. Kliethermes testimony, Tr. p. 3003, ll. 14 - 22.

[196] *Id.* p. 3016, ll. 8 - 16.

forward market forecasts.[197] Nevertheless, he proposed that if the Commission were to use historical costs, it should use seven, rather than three, years of such costs. Under such an analysis, he calculated an incremental cost of between $32.77/MWh and $34.13/MWh.[198] He also ran an analysis using "future expectations of energy prices."[199] But he was careful to list only the impact, as he calculated it, over a seven year period from service to Noranda at a $32.50/MWh rate. He did not list his actual calculations, or yearly incremental price projections, in that pre-filed testimony. But from his workpapers he testified at trial that for the period June 2015 through May 2016, he calculated an incremental cost of power, using forward power prices, of **$ **/MWh, and for the period June 2016 through May 2017, **$ **/MWh.[200] These figures are well below $34/MWh for those time periods.

In conclusion, the substantial and credible evidence is that the incremental cost to serve Noranda is highly likely to be less than $34/MWh while the rates set in this case are in effect. The parties understand however that the incremental cost is only the breakeven point. In order to benefit ratepayers by keeping Noranda on the system, it must pay something more than the incremental cost as this Commission determines it. That is why the $34/MWh rate that Noranda proposes is in the public interest; it contributes substantially to fixed costs.

D. The New Madrid Smelter Cannot Be Sustained Unless The Commission Grants Rate Relief.

The evidence presented in this case shows that without Noranda's proposed rate structure and term, the Smelter is not viable and faces substantial risk of imminent closure. Such a closure

[197] Michels Amended Rebuttal, Ex. 26, p. 22, l. 16 – p. 23, l. 2.

[198] *Id*. p. 26, ll. 6 – 12.

[199] *Id*. p. 28, l. 20 – p. 29, l. 5.

[200] Michels testimony, Tr. p. 2946, ll. 6 – 18.

would deprive consumers of the benefits provided by the Smelter on the Ameren Missouri system and would increase rates for those consumers.

To show how critical a sustainable power rate is to the New Madrid smelter's viability, Noranda provided a number of objective, reasonable and prudent financial scenarios (not forecasts) based on actual historical volatility patterns of aluminum prices. These scenarios showed conclusively that, at current power tariffs, the smelter faces a substantial risk of not being able to generate positive cash flows to pay its bills during the normal course of business operations or to attract and retain the capital necessary to support the continued operation of the smelter. Unfortunately, the actual results of the smelter's operations confirm the validity of these risk analyses. Because of the negative impact high power costs have on the smelter's cost position, Noranda has relied on access to its asset based loan ("ABL"), which is a revolving credit agreement, to sustain its business – the equivalent of paying for basic operations using its credit card. Additionally, through the date of this brief, Noranda has been unable to secure financing for its rod mill project in New Madrid. Despite the fact that the project is expected to generate a return in excess of the costs to finance it, Noranda has been unable to find a lender willing to extend the credit needed due to concerns about the viability of the smelter.

Noranda's ABL matures in February 2017 and it must be refinanced. Noranda has additional borrowing that matures in 2019 and which must also be refinanced. Without rate relief necessary to generate cash flows and liquidity, Noranda may be unable to refinance, or may only be able to obtain financing and with restrictions and covenants that would increase the likelihood of default, thus continuing to challenge the viability of the Smelter.

The evidence shows that without a sustainable power rate, the New Madrid smelter will ultimately not be able to generate positive cash flow to pay its bills during the normal course of business operations, much less any unusual or unexpected expenses that may arise due to circumstances out of Noranda's control. Because of the inability to generate positive cash flow, without a sustainable power rate, there is substantial risk that Noranda will be unable to refinance its existing debt obligations at all, or without restrictions and covenants that create additional risks to the smelter's viability. Because of the inability to generate positive cash flow and to refinance its debt, and without a sustainable power rate, Noranda will exhaust its existing sources of cash and its available borrowings, if any.

E. The Cost of Electricity and Its Financial Impact on Noranda

Noranda's primary business is the production of aluminum at its smelter in New Madrid, Missouri. Electricity and alumina are Noranda's largest costs at the smelter. In 2014, electricity represented approximately 32% of the smelter's total costs. In 2014, Noranda purchased $167 million of electricity from Ameren Missouri. Since 2008, Noranda has paid over $1 billion to Ameren. During that time, Noranda paid $211 million to Ameren Missouri in rate increases alone. At these levels, the cost of electricity has a direct impact on Noranda's ability to generate cash and liquidity.[201]

Without a reduction in the power rate, Noranda's smelter is simply not sustainable. On the other hand, if requested rate relief is granted, the smelter is sustainable. Indeed, if the PSC approves the requested power rate, Noranda's financial outlook improves and it can sustain the smelter because: (1) there is a more favorable picture for refinancing Noranda's outstanding debt as it comes due in 2017 and 2019; (2) the threat from any negative LME volatility is reduced; (3) during peak LME periods, Noranda can husband more cash to make the investments to sustain its

[201] Smith Surrebuttal, Ex. 612, pp. 2-3.

business and provide increased resistance to financial and operational shocks; and, (4) over the course of the aluminum cycle Noranda will have better capacity to reinvest in its business.[202]

F. The Aluminum Market and the Cost of Power

Aluminum is a global commodity. It is sold at a price that is based on global supply and demand, and established by trading activity on the London Metal Exchange ("LME"). An individual smelter is, in effect, a price taker and cannot set the selling price of the base product. As a result, the success or viability of a smelter is determined primarily by its cost of production.[203]

The cost of production varies among smelters based on the cost of goods and services as well as plant configuration. However, it is the cost of electricity, accounting for approximately one-third of the cost of production at most smelters, that most significantly determines whether a smelter is sustainable.[204] The impact of power rates is most dramatically shown by the recent smelter closings. In the U.S. in 1980, there were 32 smelters, producing more than 5 million metric tons. Today, there are only 8 smelters operating in the U.S., producing about 1.8 million metric tons annually. In each case, it was the high cost of power that caused the smelters to shut down.[205]

G. Noranda's Immediate Need for a Sustainable Power Rate

Noranda is in the throes of a significant liquidity crisis that, if not properly and promptly addressed, threatens imminent closure of its smelter. For the smelter to be sustained, its costs must be reduced and the "cornerstone" is power rate relief. Most pressing now, Noranda must start the process to refinance debt coming due in 2017 and 2019. Without prompt rate relief,

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[202] Smith Surrebuttal, Ex. 612, pp. 4-5.

[203] Fayne Direct, Ex. 602, p. 2.

[204] Fayne Direct, Ex. 602, p. 4.

[205] Fayne Direct, Ex. 602, pp. 3.

Noranda will not have the necessary positive liquidity and cash flow to secure refinancing and it will have to close the smelter.[206]

1. Noranda's Liquidity

Every company needs cash in order to run its business. Liquidity is cash on hand plus available borrowings. **

** At this minimum level, Noranda is still borrowing to meet its daily obligations, such as Ameren Missouri's power bill, raw materials, and payroll. As a result, the target liquidity needed for Noranda to remain a competitive smelter is $200 million. No party has challenged these liquidity amounts.[207]

Notwithstanding these needs, the following chart dramatically captures Noranda's liquidity crisis:

[206] Boyles Direct, Ex. 600, pp. 20-21.

[207] Boyles Direct, Ex. 600, pp. 6-7; Smith testimony, Tr. p. 2409.

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2. Noranda's Cash Flows and Thin Margins

Like its liquidity, Noranda's cash flow is precarious. Over the last three years, Noranda has drained cash from its cash balances. When it added cash, Noranda has only done so through financing and not from revenue generated from the sale of aluminum. Its operating cash flow is

[208] Ex. 532; Smith testimony, Tr. pp. 2464-2466.

[209] Smith testimony, Tr. pp. 2466-2471.

insufficient. Specifically, cash from operations has fallen from over $270 million in 2010 to just above $64 million in 2013. In fact, the reason why Noranda's cash balances did not fall more was its borrowings in 2012 and 2013.[210]

Complicating its cash flows, Noranda operates on generally thin margins, especially at the smelter. There is little Noranda can do to affect the LME price of aluminum and its price tends to be driven down to costs. Hence, margins are thin. Thus, any increase in a significant input like electricity that affects one competitor and not others, puts that competitor in an economically disadvantageous position. The affected competitor's costs rise, but the LME does not. Noranda finds itself in that very position as its rising power costs erode its margins that are already thin.[211]

Moreover, the recent prices for aluminum including the Midwest Premium are not helping Noranda's financial condition. On March 2, 2015, the price for aluminum including the Midwest Premium was 99.02 cents per pound. The last time the price was below $1 per pound was May 29, 2014, when it was 99.944 cents per pound. From May 2014 to March 2015, the price for aluminum averaged $1.0904 per pound. The recent prices are 10.02 cents less per pound, which equates to approximately $75 million in lost revenues for Noranda.[212]

3. <u>Noranda's Financial Condition Has Not Improved</u>

During the last case, Noranda focused on its concerns about its liquidity and cash flow. These concerns were not misplaced. The failure to secure a sustainable power rate has created both short-term and long-term peril for the smelter. The short-term problem is the need to refinance Noranda's debt in 2017 and 2019. The long-term threat lies in Noranda's inability to

[210] Schwartz Direct, Ex. 610, pp. 10-12

[211] Schwartz Direct, Ex. 610, pp. 7-8

[212] LME prices, Platts.com (McGraw Hill Financial).

husband cash to reinvest in its business and to weather the inevitable lows of the LME price cycle.[213]

H. Noranda’s Need to Refinance in 2017 and 2019

1. ** **

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2. Noranda’s Loans Come Due in 2017 and 2019

Noranda has a revolving asset based loan facility (“ABL”), which works like a “credit card” in that it allows Noranda to continue to fund its business operations when its cash runs out. Indeed, Noranda has repeatedly accessed its ABL since June 2014 in order to meet its daily obligations. The ABL comes due in February 2017, and it must start the process of replacing the ABL at the beginning of 2016. If Noranda is unable to renew the ABL, or is only able to renew

[213] Smith Surrebuttal, Ex. 612, p. 8.

[214] Boyles Direct, Ex. 600, p. 21; Smith testimony, Tr. pp. 2424-2428.

part of the ABL, Noranda's liquidity will immediately decline and its viability as a company will be immediately threatened and compromised.[215]

Noranda also has a large amount of long-term debt, or what some call a mortgage, that comes due in 2019. Assuming that Noranda is viable and able to refinance its ABL in 2017, it expects to begin the work to replace its remaining long-term debt in early 2018.[216]

3. Noranda Needs A Sustainable Power Rate to Refinance its Debt

Lenders rely heavily on a borrower's ability to liquidate collateral to repay a loan, and they are unwilling to extend or refinance existing debt when they perceive a meaningful risk of default and a lack of viability of the borrower. Lenders also look at historical results of a company when they are asked to make a loan. Therefore, it is critical that, when it undertakes its refinancing efforts, Noranda have better cash flows for 2015 through 2017, and much better projected cash flows for the three to five years after the loan. The only way to achieve those positive cash flows is a viable power rate for the smelter.[217]

As Schwartz[218] explained, the critical importance of Noranda's historical financial results is seen in the recent actions by Moody's and Standard & Poors, both of which downgraded Noranda's credit rating to a "highly speculative" grade of risk.[219] Standard & Poor's pointed to Noranda's liquidity issues and declining operating performance as important factors behind its rating decrease.[220] A lower credit rating signals to lenders that there are doubts about the borrower's credit worthiness. They will look skeptically at optimistic business scenarios, and

[215] Boyles Direct, Ex. 600, pp. 21-22; Smith Surrebuttal, Ex. 612, pp. 5-6.

[216] Boyles Direct, Ex. 600, pp. 22-23.

[217] Boyles Direct, Ex. 600, pp. 22-23.

[218] Dr. Steven Schwartz is an economist and Managing Director at Alvarez & Marsal Global Forensics and Disputes.

[219] *Research Update: Noranda Aluminum Holding Corp. Rating Lowered To 'B-' From 'B'; Outlook Is Stable;* pp. 2-3 Rationale; Oct 13, 2014.

[220] Schwartz Direct, Ex. 610, p. 11.

they will look at the sensitivity of performance forecasts to changing assumptions. If they ultimately deem a borrower worthy of a loan, they will charge more to make that loan. Alternatively, they can view the borrower as not credit worthy and simply decline to lend. What makes this particularly problematic here is that Noranda was already starting from a junk credit rating. The downgrade in October 2014 shows Noranda's credit deteriorating even further. With Noranda needing to begin the process of refinancing a substantial portion of its debt in about a year (since it takes about 12 to 15 months for the refinancing process to be completed), its current financial position—already weak—will be evaluated substantially in light of future prospects that will be sharply affected by electric rates.[221]

As Harris[222] explained, Noranda will be unable to raise capital without first fundamentally improving its cash flow and thereby demonstrating its long-term viability. Lenders loan money that they have a reasonable expectation will be repaid, with interest, and equity owners invest money for a return, but typically will not invest in a company with Noranda's financial metrics, particularly where they perceive a meaningful risk of financial distress and impairment in long-term viability that could completely wipe out their equity investment.[223] In simple terms, no bank will lend to a highly leveraged company like Noranda, absent an immediate expectation for a fundamental improvement in financial metrics and a belief in the medium to long-term viability of the company. Similarly, no other debt investor is likely to lend and no equity investor is likely to invest new capital in such a company. The current drain on cash flow caused by Noranda's unsustainable power rate will not position it to be considered an attractive borrower to banks or debt investors or an attractive investment for equity

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[221] Schwartz Direct, Ex. 610, pp. 13-15.

[222] Thomas Harris is a banker who specialized in leveraged financing. He assisted in the financing for the acquisition of Noranda, and worked at Noranda from 2009 to 2010.

[223] Harris Direct, Ex. 604, pp. 4-5.

investors.[224] On the other hand, with the proposed power rate yielding approximately $40 million or more in cost savings per year, together with the efficiency initiatives already undertaken at Noranda, Noranda would likely be able to refinance its ABL and other indebtedness as well as obtain financing for its important projects in the future.[225]

I. Noranda's Continuing Need for Capital Improvements

As a result of poor cash flow and lower liquidity, Noranda has gone through a stretch when it has been unable to make all of the capital expenditures required for its business. It has deferred capital spending, and its capital expenditures are less than its depreciation. There are at least two implications of this. First, its capital expenditures are currently insufficient to sustain the business at its current scale of operations for an extended period of time. It is not a sustainable level of capital expenditures. Second, in order to be sustainable at this scale—or to increase its scale of operation and/or efficiency, Noranda will have to increase its level of capital expenditures in the future above what would be normal "maintenance" levels.[226]

In order to address its capital expenditure needs, Noranda has identified projects requiring it to spend over ** ** over the next 10 years. These levels are real and needed. Without that level of capital spending, the smelter is not viable.[227] For example, in the past several months, Noranda had an abnormal level of pot failures at the smelter. It had to invest approximately $18 million in the first quarter of 2015 just to solve this problem.[228]

J. Lenders will not use the CRU Forecast When Considering Noranda's Debt Refinancing

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[224] Harris Direct, Ex. 604, p. 6.

[225] Harris Direct, Ex. 604, pp. 7-8.

[226] Schwartz Direct, Ex. 610, p. 12.

[227] Boyles Direct, Ex. 600, pp. 9-10.

[228] Smith Surrebuttal, Ex. 612, pp. 9-10.

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The CRU forecasts currently show a modest increase in the future prices for aluminum but they will not justify refinancing Noranda's debt. At best, these forecasts provide some guidance up to 12 months into the future. They do not provide reasonable guidance upon which lenders will rely with regard to potential aluminum prices two to five years into the future because of the volatility in the marketplace.

1. <u>There is Great Volatility in the Aluminum Marketplace</u>

Aluminum prices are highly volatile. Consequently, although aluminum price forecasts and forward curves provide a reasonable starting point for evaluating the future, they are not sufficient to evaluate future risks and, therefore, do not provide a reliable basis to assess the sustainability of a smelter.[229] Indeed, Bank of America/Merrill Lynch reported on March 4, 2015, that it was dropping its forecast for aluminum prices by 7.8% for 2015, 15.9% for 2016, and 19.3% for 2017.[230]

The viability of any business refers to its ability to survive over the course of the business cycle—that is to meet its obligations as they come due while investing the necessary capital to operate the business. This issue is particularly acute for Noranda because of the extreme volatility and the steep troughs of an aluminum pricing cycle. If an aluminum smelter cannot generate sufficient cash and profits when prices are above cycle average, it will not be able to survive during the periods when prices are below cycle average.[231]

2. <u>Aluminum Prices are Not Likely to Rise in the Near Term</u>

[229] Pratt Direct, Ex. 608, p. 2.

[230] Ex. 530; Humphreys Testimony, Tr. pp. 2157-2163.

[231] Smith Surrebuttal, Ex. 612, pp. 7-9.

As Pratt[232] testified, the initial conditions and the near term outlook for aluminum do not suggest a strong likelihood of higher prices in 2016 or 2017. The initial conditions include a very high level of industry inventories, a low degree of capacity utilization, a continuing rapid expansion of production capacity in China, and a slowdown in China's economic growth. There are also some significant downside risks. One is that the financial demand for inventories, which has supported prices despite the high inventory levels, will subside as interest rates begin to rise in the next two years. In other words, it will not be as attractive for banks to finance aluminum inventories once the cost of money begins to rise. A second is that China could relax its restrictions on the export of primary aluminum. These are currently discouraged by a 15% export tax, but industry is lobbying the Chinese government to have this tax reduced or removed. Meanwhile, Chinese smelters have decided to stockpile 1.2 million tons of excess production this year.[233]

Simply put, poor conditions exist now in the aluminum market. As Pratt testified, the central view of CRU in its January 2015 forecast is for very little change in the annual average price in 2015 followed by a 5.5% decline in real terms in 2016. CRU also assesses downside risks and produced a downside scenario with prices 15% below the base case in 2016 and 2017.[234]

3. <u>Noranda's Scenarios Provide a Reasonable Tool for Price Volatility</u>

Since aluminum prices are uncertain and volatile, prices do not follow a straight line but fluctuate with a wide range around a trend. Although one cannot predict the timing of price cycles, one can use scenarios of their amplitude and frequency to stress test business plans. To

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[232] Colin Pratt is a Managing Consultant of CRU, and is Director of is Valuation Practice Area. He has over 37 years of experience in commodity market analyses, especially aluminum.

[233] Pratt Surrebuttal, Ex. 609, pp. 11-12.

[234] Pratt Surrebuttal, Ex. 609, p. 12.

forecast the timing of price cycles would be misleading. That is why it is important to regard these price paths as scenarios rather than forecasts. It is important to consider the variance of prices or volatility in assessing business risks.[235]

To give an analogy, for a ship navigating a channel the minimum depth of water is more important than the average depth of water. Or, to take another example, if we know from historical records that the average rainfall in a 4-week period is seven inches, our mean expectation per day is one-quarter inch. However, it is very unlikely that we will get exactly a quarter inch of rain each day. In fact the daily rainfall may vary from zero to seven inches. If you were designing drainage capacity, you would need to consider the maximum rainfall. The point is that there are circumstances in which average expectations need to be supplemented by an analysis of variance.[236]

Aluminum companies face an uncertain and volatile price. One can predict a mean expected price over a long period of time, such as ten years, within reasonably narrow confidence limits. However, for shorter time periods of one year we are faced with a wide potential range of prices.[237] As a result, it is entirely objective, reasonable, and prudent to rely on representative volatility scenarios based upon historical experience. In fact, for purposes of stress testing a company's liquidity and viability, it would be inappropriate and imprudent to assume there will be no aluminum price volatility (as Ameren Missouri's expert witnesses do).[238]

In this case, Noranda produced a balanced set of 11 different scenarios stress testing its liquidity and cash flow based on the future price of aluminum.[239] As Pratt testified, these

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[235] Pratt Surrebuttal, Ex. 609, p. 16.

[236] Pratt Surrebuttal, Ex. 609, p. 3.

[237] Pratt Surrebuttal, Ex. 609, p. 3.

[238] Boyles Surrebuttal, Ex. 601, p. 5.

[239] Pratt Surrebuttal, Ex. 609, p. 16.

scenarios are a reasonable and representative set for stress testing Noranda's business plans.[240] The method chosen by Noranda also has the advantage that it reflects potential volatility in aluminum prices using real historic data thereby making it more reasonable and representative.[241]

4. **

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As Schwartz testified, a reduced rate such as that Noranda proposed is critical to the smelter's viability. **

[240] Pratt Surrebuttal, Ex. 609, pp. 16-17.

[241] Pratt Direct, Ex. 608, p. 22.

[242] Schwartz Direct, Ex. 610, p. 19.

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As Harris concluded, Noranda will be unable to secure financing to maintain operations under Ameren Missouri's current power rates. Even with the savings under Noranda's proposed rate, Noranda may still find it challenging to refinance its debt or attract new capital. However, Noranda's proposed power rate and long-term stability provided by the 7 year proposed term will have a meaningful positive impact on Noranda's cost structure, making it significantly more likely that Noranda will be able to refinance its debt and maintain operations at the smelter.[244]

K. Noranda has Disclosed to the Public its Precarious Financial Situation Through the SEC

In its 2014 Form 10-K, Noranda disclosed the possibility of the smelter closure and the other risks associated with an unsustainable power rate as well as the possibility of bankruptcy:

> **If we are unable to successfully finalize power issues at our New Madrid facility, we may have to curtail this facility.**
>
> . . .
>
> Curtailing unprofitable production to reduce our operating costs requires us to incur substantial expense, both at the time of the curtailment and on an ongoing basis. Our facilities are subject to contractual and other fixed costs that continue even if we curtail operations at these facilities. These costs reduce the cost saving advantages of curtailing unprofitable aluminum production.

[243] Schwartz Direct, Ex. 610, pp. 22-23.

[244] Harris Direct, Ex. 604, pp. 4-5.

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> If any production curtailment or other restructuring does not achieve sufficient reduction in operating expenses, we may have to seek bankruptcy protection for some or all of our subsidiaries; we could also be forced to divest some or all of the subsidiaries. If we were to seek bankruptcy protection for any of these subsidiaries, we would face additional risks. Such action could cause concern among our customers and suppliers, distract our management and other employees and subject us to increased risks of lawsuits. Other negative consequences could include negative publicity, which could have an impact on the trading price of our securities and affect our ability to raise capital in the future.[245]

In its Form 10-K, Noranda also disclosed volatility as a risk factor in its business:

> Our operating results depend substantially on the market for primary aluminum, a cyclical commodity whose prices have historically been volatile […]. Primary aluminum prices are subject to regional and global market supply and demand and other related factors. Such factors include production activities by competitors, production costs in major production regions, economic conditions, interest rates, nonmarket political pressures, speculative activities by market participants and currency exchange rates. Extended periods of industry overcapacity may result in a weak pricing environment and margin compression for aluminum producers, including Noranda.[246]

L. Witnesses Mudge's and Humphreys' Criticisms Ring Hollow

1. Mudge

A business like Noranda cannot simply assume that the average price of aluminum, or that a one-year projection of price, will prevail into the future given price volatility. Mudge is a paid witness with no responsibility to employees, shareholders, or the community in which Noranda operates. If Mudge's opinions are wrong (as Noranda believes they are) and the smelter perishes, it is Noranda's employees and shareholders, the communities in which Noranda does business, and Ameren Missouri's other ratepayers who will suffer. Noranda has a personal responsibility to keep the New Madrid smelter operational and to make it viable. Therefore,

[245] Ex. 533, p. 17 (bold in original and emphasis added); Smith testimony, Tr. pp. 2472-2476.

[246] Boyles Surrebuttal, Ex. 601, p. 12.

Noranda must take into account the volatility of the aluminum price in planning its sustainability.[247]

First, Mudge misrepresents how Noranda's rate request was determined and what the comparative electricity cost data was intended to show. Contrary to Mudge's mischaracterization, the proposed reduced rate was <u>not</u> determined based on a comparison of the cost of other smelters. The proposed rate was determined based on a robust stress test designed to determine what power rate Noranda could afford given the volatility of the LME. Likewise, the use of comparative electricity costs among smelters as shown on Exhibit HWF-1 included in Fayne's[248] direct testimony was not intended to be determinative, but rather was intended to show that the proposed rate was reasonable in the context of the industry. And that is exactly what it shows; at $32.50/MWh and even at $34/MWh, the cost of electricity to New Madrid would be reasonably within the range of the cost to other smelters in the U.S. and slightly above the average rate smelters receive globally.[249]

Second, Mudge criticizes Noranda's cost data because it does not reflect the risks and costs embedded in the various power supply arrangements such as investment commitment, employment commitments, closure penalties and market risk. It is important to note that Noranda did make comparable commitments as part of its request in the last case and, more importantly, Smith has confirmed those commitments in this case. Thus, the comparison of the proposed rate is in fact on an apples-to-apples basis since the "risks" would be comparable. But Mudge's criticism of the cost data is simply misplaced. For even under the current rate structure, Noranda has significant risk related to its cost of electricity. As Fayne pointed out in the last

[247] Smith Surrebuttal, Ex. 612, p. 14.

[248] Henry Fayne is a recognized consultant in the electrical energy sector primarily in the area of power contracts for aluminum smelters in the United States.

[249] Fayne Surrebuttal, Ex. 603, pp. 2-3.

case, the cost of electricity in 2011 to Noranda was $33.65/MWh. In 2013, the cost was $43.50/MWh, an increase of more than 31% in just 2 years.[250]

Third, Mudge suggests that lenders are likely to assume higher aluminum prices than those assumed in Boyle's scenarios, simply because Noranda has relied upon certain industry analyst forecasts in the past, in its discussions with rating agencies and equity investors, that assume higher prices. This is incorrect. While reasonable people can agree that many scenarios for aluminum prices and required capital investment could come to pass for Noranda, this is precisely why banks and institutional lenders use conservative forecasts and downside cases to determine the creditworthiness of a borrower. In fact, regardless of what scenario Noranda presents to lenders, they are likely to discount anything they view as overly positive assumptions for factors such as prices.[251] Indeed, Bank of America/Merrill Lynch recently reported that it was dropping its forecast for aluminum prices by 7.8% for 2015, 15.9% for 2016, and 19.3% for 2017. Neither Mudge nor Ameren had any response to this announcement.[252]

Fourth, Mudge points to the CRU forecast and suggests Noranda should simply use those assumptions and everything will be fine. When a CFO does budgeting and planning, particularly in relation to a company's very ability to refinance its debt and remain viable in the long-term, it is prudent to be conservative. When lenders evaluate Noranda's credit-worthiness, they will likely discount any assumptions they see as overly rosy or aggressive and give more credibility to a financing base case with more conservative assumptions, such as Mr. Boyles'.[253]

2. <u>Humphreys</u>

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[250] Fayne Surrebuttal, Ex. 603, p. 3.

[251] Harris Surrebuttal, Ex. 605, p. 2.

[252] Ex. 530; Tr. pp. 2157-2163.

[253] Harris Surrebuttal, Ex. 605, p. 5.

Like Mudge, Humphreys is a paid witness with no responsibilities to employees, shareholders, or to the community in which Noranda operates. He spent less than one week on this engagement,[254] but he made no independent analysis of Noranda's liquidity needs,[255] its cash needs,[256] and did not perform any stress or volatility test of Noranda.[257] Although his real world experience with a large company with many smelters across the world,[258] he did acknowledge that Noranda had only one smelter,[259] Noranda was less likely to survive the stresses of the aluminum marketplace, and the high cost of power.[260]

First, although he admits that aluminum prices hover in the troughs more than the peaks,[261] Humphreys argues that the proper aluminum price forecast for evaluating Noranda's financial condition is the CRU forecast. He argues that because it is not possible to know precisely how prices will evolve or to locate prices in the context of the price cycle, it is incorrect to do anything other than accept the CRU price forecast as it is.

As an economic matter, Humphreys' conclusion is not sensible. His argument completely ignores the purpose for which the aluminum stress tests on price scenarios are used in this case. He provides no evidence or economic basis for his assertion that the CRU forward forecast somehow embodies or reflects the underlying volatility of aluminum prices. The forward forecast takes, as a starting point, the price trend from the preceding periods. But a price trend, by its nature, smoothes out volatility. It ignores year-to-year variation (i.e., volatility), in

[254] Humphreys Testimony, Tr. p. 2133.

[255] Humphreys Testimony, Tr. p. 2141.

[256] Humphreys Testimony, Tr. p. 2141.

[257] Humphreys Testimony, Tr. p. 2142.

[258] Humphreys Testimony, Tr. p. 2138.

[259] Humphreys Testimony, Tr. p. 2138.

[260] Humphreys Testimony, Tr. p. 2142-2143.

[261] Humphreys Rebuttal, Ex. 19, p. 7.

order to project a set of prices going forward. It captures only the directional movement of prices. With a trend line, it is overwhelmingly likely that, in any given year, the projected price will be wrong. Rather than accounting for any underlying volatility, the CRU forward forecast statistically removes it. Since there is no variance in the CRU forecast, it does not incorporate volatility at all, and the CRU forecast represents a single, fixed scenario. That means that the prices in the CRU forecast are not appropriate to assess Noranda's financial condition during the price cycle.[262]

As Schwartz testified, a potential lender will be concerned with the likelihood of a borrower being able to repay its loan. It will be looking to the indicia of a firm's ability to do that, such as free cash flow. To get a good estimate of what free cash flow is likely to be going forward, lenders will be focused on future revenues and profitability. Therefore, it will want—among other things—reasonable estimates of future prices. It will seek price forecasts that are neither unreasonably optimistic nor pessimistic. As a result, the CRU forward curve forecast would be rejected. Lenders want to be assured that they will be repaid under a variety of possible outcomes for aluminum prices. Accordingly, they will consider a variety of aluminum price scenarios when making a lending decision. A reasonable price scenario that threatens the company's ability to repay the loan would be taken very seriously by a lender. More reasonably, in Noranda's case, a lender would want a forecast that reflects a price path that captures price movements—up and down—because Noranda's future financial condition depends importantly on that path. The CRU forward curve is not such a forecast.[263]

As Harris testified, lenders will also typically take a management view of a "base case" forecast and then sensitize factors such as aluminum prices. Lenders may consider expert

[262] Schwartz Surrebuttal, Ex. 611, pp. 6-7.

[263] Schwartz Surrebuttal, Ex. 611, pp. 8-9.

forecasts, as well as market forecasts for aluminum prices, such as the forward curve for the price of aluminum, when making their credit decisions. However, lenders often also run downside cases that have price assumptions below the prices forecasted by the experts and the markets. To the extent that lenders view management's forecast as conservative relative to expert forecasts, such as CRU's, lenders will typically discount the driving assumptions to a lesser extent and be more willing to rely on management guidance. In other words, lenders gain assurance when the expert projected prices are higher than those forecasted by management. Again, conservative forecasts are most appropriate when examining a company's very ability to refinance its debt and remain viable.[264]

3. <u>Noranda Cannot Hedge</u>

For multiple reasons, hedging is not going to solve Noranda's problems. Hedging is beneficial when a company can lock in market prices for its output that will allow it to weather periods of much lower prices. Both Mudge and Humphreys suggest that Noranda should simply hedge its way out of its financial predicament. Yet, Humphreys has no prior experience in hedging[265] and did not do any analyses of Noranda's financial ability to engage in hedging.[266] Likewise, Mudge did not conduct any independent analyses. However, at a B3 corporate rating, Noranda is unlikely to have access to hedging without having to post prohibitive amounts of capital, further eroding its liquidity. At a low-single B rating, hedging counterparties are unlikely to want to enter into a contract with Noranda for the same reason that Noranda is likely to be unable to refinance without rate relief. Hedging counterparties don't want to deal with

[264] Harris Surrebuttal, Ex. 605, p. 7.

[265] Humphreys Testimony, Tr. p. 2151.

[266] Humphreys Testimony, Tr. p. 2171-2172.

companies whom they feel may not be viable in the long term.[267] In addition, because of Dodd-Frank regulations, fewer and fewer banks are positioned to serve as a counterparty for such hedges and those banks that are interested and able to serve as hedge counterparty have restrictions about how far into the future they may hedge, and generally require collateral (margin accounts, letters of credit, etc.) based on their total exposure, not the current fair value of the hedge. This collateral would consume Noranda's available liquidity and reduce its ability to weather operational and financial disruptions that have a reasonable likelihood of occurring.[268]

M. Ameren Missouri's Proposal to Terminate or Suspend the CCN to Make Noranda Into a Wholesale Customer is Not in the Public Interest, Would Result in Closure of the New Madrid Smelter and Should Not Be Considered

The wholesale arrangement posited by Ameren Missouri in this case is of no benefit in resolving the issues raised by Noranda in this proceeding, and would do nothing to secure a long-term sustainable power supply for the New Madrid facility. Accordingly, the Commission should not be sidetracked into paying substantial attention to this illusory "solution," and should proceed with its deliberations on the issues before it in this proceeding.

In the Rebuttal Testimony of Matt Michels, Ameren Missouri proposed what it characterizes as a "solution" to the issues raised by Noranda concerning the retail rates it pays for the power it purchases from Ameren Missouri. According to Mr. Michels, the Ameren Missouri proposal would satisfy Noranda's need for a long-term sustainable power rate, while avoiding the problems that Ameren Missouri asserts would be caused by the relief Noranda has requested in this case. Under the terms of that proposal: (i) the agreement under which Noranda currently purchases power would be terminated; (ii) the Certificate of Convenience and Necessity ("CCN" or "Certificate") would be "canceled or suspended"; and (iii) Noranda would take power under a

[267] Harris Surrebuttal, Ex. 605, p. 8.

[268] Boyles Surrebuttal, Ex. 601, p. 13.

"long-term wholesale power contract" with market-based pricing for a term of five years, with some renewal rights at a renegotiated price.[269] Ameren Missouri's proposal was further explained in the Surrebuttal Testimony of Michael Moehn, as follows:

> First, Noranda and Ameren would need to agree to terms of service and prices for the wholesale contract. Secondly, the Commission would need to approve this arrangement, confirm that entering into the arrangement was a prudent decision for Ameren Missouri and that the costs and revenues associated with this transaction will be reflected in the FAC … Third, there would be no continuing obligation on Ameren Missouri's part to serve Noranda under the existing certificate of convenience and necessity authorizing/requiring Ameren Missouri to provide retail service to Noranda …[270]

Having considered the "solution" put forward by Ameren Missouri with a good deal of care, Noranda believes that the proposal would compound, rather than resolve its problems over the long term. In fact, Noranda believes that the arrangement proposed by Ameren Missouri ultimately would leave Noranda in a far more perilous position than it is in today. Moreover, even if the proposal were to provide an effective resolution of the issues Noranda has raised, its fundamental components are unsound. Therefore, Noranda urges the Commission not to be distracted by the Ameren Missouri proposal in deciding the rate case that is before it.

N. <u>The Ameren Missouri proposal would put Noranda at risk by relieving Ameren Missouri of its obligation to provide Noranda with adequate power and by divesting the PSC of jurisdiction over the rates Noranda pays, not only during the period of the wholesale contract, but possibly thereafter</u>

In Ameren Missouri's application for the Certificate of Convenience and Necessity in Case No. EA-2005-0180, (the "CCN Application"), it presented some of the reasons why issuance of the CCN was in the public interest. Among the considerations put before the Commission at that time were that Noranda is a major employer in Southeast Missouri; that Noranda and its employees pay substantial state taxes supporting a wide variety of governmental

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[269] Michels Amended Rebuttal, Ex. 26, p. 31 and 33.

[270] Moehn Surrebuttal, Ex. 29, p. 15.

and institutional operations; and that for these and other reasons, Noranda is an essential economic engine for the region and the entire state of Missouri. As also explained by Ameren Missouri in the CCN Application, a safe, reliable and adequate long term supply of electric power and energy is critical to Noranda's business. The aluminum smelting operation is very energy intensive, and the cost of electricity is by far the largest cost incurred by Noranda in operating its plant. Moreover as noted in the CCN Application, due to the nature of the aluminum smelting operation a loss of power would have dire consequences for Noranda, because "aluminum smelting plants cannot, as a practical matter, be started up, shut down, and then restarted again without significant, and sometimes unalterable, impacts."[271] For these, and other reasons set forth in the application, the Commission had ample basis to determine that long-term public utility service at just and reasonable rates is "essential to Noranda's continued viability, and Noranda's continued viability is critical to the viability of Southeast Missouri and the state of Missouri."[272] Thus, on the basis of the application, the stipulation reached by the parties to the proceeding, and the other facts in the record before it, the Commission concluded that "the requested extension of UE's service area is necessary and convenient for the public service and should be granted."[273]

For the reasons first articulated by Ameren Missouri in the CCN Application, a reliable and adequate supply of energy at just and reasonable prices is as essential to the viability of the New Madrid smelter today as it was at the time it was issued. Accordingly, it is critical to Noranda that the Commission maintain the jurisdiction needed to assure that Ameren Missouri provides such power to the New Madrid facility at fair rates. Moreover, there continues to be a

[271] CCN Application, p. 7.

[272] *Id.* at 8.

[273] *Application of Union Electric Company*, Case No. EA-2005-0180, Order Approving Stipulation and Agreement dated March 10, 2005, p. 7.

compelling *public* interest in maintaining such jurisdiction, because Noranda's presence on Ameren Missouri's system benefits Ameren Missouri's ratepayers and is critically important to Missouri's economy.

Although Ameren Missouri has characterized its proposal as a "solution" to the rate issues raised by Noranda in this case, its ultimate effect will be to relieve Ameren Missouri of any long-term obligation to supply power to the Noranda smelter and to deprive the Commission of any jurisdiction over the reliability of service provided to Noranda or the rates that Ameren Missouri charges for its service. Ameren Missouri makes no bones about this objective in its testimony. Thus, Mr. Michels makes clear that upon termination of the five-year contract "Ameren Missouri would no longer bear an obligation to serve Noranda and would no longer need to acquire resources necessary to serve Noranda."[274] When asked what would happen at the end of the initial five-year contract period, Mr. Michels responded that Noranda might attempt to arrange for power on the "open market," extend the wholesale arrangement with Ameren Missouri at a new price or seek legislative relief.[275] Thus, Ameren Missouri would have neither a contractual nor a regulatory obligation to serve Noranda at the end of the five year period. Thus, although the proposal may be cloaked as one intended to provide relief to Noranda, it is really an attempt by Ameren Missouri to rid itself of existing regulatory obligations and to divest the Commission of jurisdiction, in both the short term and in the future. The particular elements of the proposal may advance the interest of Ameren Missouri's shareholders to achieve greater profits by eliminating a large consumer from Missouri regulatory and legislative participation.

[274] Michels Amended Rebuttal, Ex. 26, p. 35. *See also* Moehn Surrebuttal, Ex. 29, p. 15 ("Third, there would be no continuing obligation on Ameren Missouri's part to serve Noranda under the certificate of convenience and necessity authorizing/requiring Ameren Missouri to provide retail service to Noranda.").

[275] Michels Amended Rebuttal, Ex. 26, p. 34.

However, as explained below, Ameren Missouri's wholesale proposal is detrimental to the interests of Noranda, other ratepayers and the state of Missouri.

1. <u>The Commission would lose jurisdiction over rates during the term of the agreement because the arrangement is characterized as a "wholesale contract"</u>

Under the Federal Power Act, 16 USC § 824, *et seq*., ("FPA") the Federal Energy Regulatory Commission ("FERC") has exclusive jurisdiction over the sale by public utilities of electric energy at wholesale in interstate commerce.[276] In particular, FERC has the exclusive power to set rates for such interstate wholesale power sales.[277] Ameren Missouri is a "public utility" within the meaning of the statute because it owns and operates facilities subject to the jurisdiction of FERC and sells power on the wholesale market in interstate commerce. Accordingly, FERC – and not the Commission – would have jurisdiction over rates and service reliability during the term of that agreement.[278]

2. <u>If the parties were to enter into the proposed wholesale transaction, Ameren Missouri may be relieved of its obligation to provide power to Noranda after the term of the contract -- whether or not the Commission approves the cancellation of the CCN</u>

Ameren Missouri's testimony is unclear as to whether Ameren Missouri would demand, as a condition to the proposed transaction, that the Commission cancel the CCN or merely "suspend" its operation for the term of the agreement. Certainly, if the Commission were to cancel the CCN (and, as discussed below, do so in accordance with applicable substantive and procedural requirements), Ameren Missouri would be relieved of its "regulatory compact" obligations *vis-a-vis* Noranda, and the Commission would relinquish its jurisdiction over any

[276] 16 U.S.C. §§ 824, 824d, and 824e.

[277] *Id.* § 824(b).

[278] It should be noted that under federal law, "wholesale" transactions are those that involve a "sale of electric energy to any person for resale." 16 U.S. C. § 824(d). Noranda assumes that Ameren Missouri would seek to structure the transaction so that if fits within this definition.

future power sales between those parties. Moreover, there is material legal risk that the same result would follow from a "suspension" of the CCN for two reasons.

First, Noranda would be entering into the arrangement with Ameren Missouri pursuant to the rights conferred upon aluminum smelters by § 91.026.1 to purchase electric power and delivery services from "any provider." Under subdivision 6 of that provision, once an aluminum smelting facility exercises that right "no past supplier of energy and related services shall have any obligation to provide electric power and energy and delivery services to such aluminum smelting facility except as may be established by written contract."[279] While Noranda would dispute the notion that Ameren Missouri had gained the status of a "past supplier" of power by entering into a new wholesale arrangement, it can be expected that Ameren Missouri would take a contrary position and seek nullification of its regulatory obligation by operation of law.

Moreover, Ameren Missouri's current obligation to serve arises by virtue of the CCN and may disappear in the event the CCN were to lapse as a result of its suspension. Under § 393.170, a public utility must secure a CCN prior to exercising any right or privilege under any franchise, and *also* where the exercise of its rights and privileges "*shall have been suspended for more than one year*." The courts view a company's "rights and privileges under its corporate franchise as the unitary, indivisible sum of all its corporate powers … merged into the single privilege of operating an electric utility." *State of Missouri v. PSC*, 38 P.U.R. 3rd 451 (Mo. Ct. App. 1960). If the CCN were to be suspended, one might argue that Ameren Missouri's state-based privilege of operating a public utility within the Noranda service area was also suspended for a period of more than one year, and that a new CCN would be needed by Ameren Missouri before resuming

[279] *Id.*

those retail operations. While Noranda would vigorously dispute any such argument, there is material risk that it would be asserted.

3. Ameren Missouri's Wholesale Proposal Is Unsound

(a) The Parties to a Wholesale Contract May Not Terminate the CCN

The Commission's well-founded and record-based determination that issuance of a CCN for the Noranda service area is in the public interest cannot be nullified by a contract between private parties. The reason for this is that in wielding its authority under Missouri statutes, the Commission is exercising the police power of the State.[280] Private contracts cannot affect determinations made in the exercise of such powers, because of the mandate under the Missouri Constitution that "[t]he police power of the state shall never be surrendered, abridged, or construed to permit corporations to infringe the equal rights of individuals, or the general well-being of the state."[281] Thus, "the power of the public service commission is an exercise of the police power of the state granted by the lawmaking power to that tribunal and overrides all contracts, privileges, franchises, charters or city ordinances."[282]

(b) Cancellation of the CCN Cannot be Effectuated by Commission "Approval" of a Contract Between Ameren Missouri and Noranda

Canceling the CCN by means of a contract approved by the Commission would be equally defective. In the instant rate case the Commission is not reviewing the facts and circumstances that were the basis for the issuance of the CCN in the first instance; and even if it were to do so, it would find that Noranda remains the largest employer in Southeast Missouri; that it continues to be a mainstay of the economy in that region of the state; and that now, more

[280] *State ex rel City of Sedalia v. Public Service Commission*, 275 Mo. 201, 2014 S.W. 497 (Mo., 1918).

[281] Mo. Const. Art. XI; *Pub. Mut. Cas. Co. v. Scharz,* 422 S.W.2d 301, 304 (Mo. 1967).

[282] *State ex rel. City of Kirkwood v. Pub. Serv. Comm'n of Missouri*, *supra; see*, also, *Norman v. Baltimore & Ohio Railroad Co.* 294 US 240, 308 (1935) ("Parties cannot remove their transactions from the reach of dominant constitutional power by making contracts about them.").

than ever, Noranda requires a safe and reliable source of power at just and reasonable rates. Thus, there is no basis in the record for the Commission to reconsider its previous determination that extension of the Ameren Missouri service area to include the Noranda facility is in the public interest. Certainly, a stop-gap contract affording Noranda the opportunity to purchase wholesale power for a period of five years provides no valid basis whatsoever for such an action. Determinations of the Commission must be supported by a record including competent and substantial evidence, § 536.140; *State ex rel. Chicago, Rock Island & Pacific Railroad Company v. Public Service Commission,*[283] and cannot be premised wholly on the wishes of private contracting parties. Thus, the Commission's orders approving stipulations are valid only if they are backed by competent and substantial evidence and include written findings of fact. In *State ex rel. Fischer v. Pub. Serv. Comm'n of Mo.*,[284] the Western District overturned a Commission order that approved a stipulation. Among other failures, the Commission made conclusory findings of fact and failed to find the facts necessary to adopt the stipulation. Therefore, the Commission cannot simply adopt a stipulation without conducting its own analysis.

Ameren Missouri provides no foundation for the cancellation of CCNs previously issued by the Commission.[285] In the few circumstances where a certificate has been canceled, the Commission has done so only after a request for cancellation was duly made by the provider, notice and an opportunity to intervene had been afforded to interested parties, and a substantive basis for the cancellation was established on the record before the Commission.[286] Moreover, we

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[283] 312 S.W.2d 791, 794–95 (Mo. banc 1958)

[284] 645 S.W.2d 39, 41-42 (Mo. Ct. App. 1982)

[285] We have found no instance where a CCN authorizing a public utility providing electricity to a service area has been canceled, thereby relieving the utility from its obligation to provide power at just and reasonable rates.

[286] See, e.g., *In the Matter of the Application of Ozark Shores Water Company for an Order Canceling the Certificate of Public Convenience and Necessity Issued to it in Case Number WA-99-99 for Water and Sewer Service at a Condominium Complex Known as Summerhaven Condominiums,* Case No. WD-2001-70*; In the*

have identified no instance where the Commission has "suspended" a CCN nor any provision of Missouri law or regulation that contemplates such an action by the Commission.

(c) <u>Ameren Missouri's Proposal to Include All of the Costs and Revenues Associated With the Transaction in the FAC Unsound and Creates Material Risk for Noranda and Other Ameren Missouri Ratepayers</u>

As Mr. Dauphinais, Ms. Mantle, and Ms. Kliethermes all testified, either at hearing or in their pre-filed testimonies, the cost to serve a wholesale customer can and should be allocated to the wholesale jurisdiction.[287] Ms. Kliethermes was clear in her testimony that because Ameren Missouri's existing wholesale contracts are insignificant, the parties have agreed that the costs to serve those wholesale customers will be baked into retail rates, but the revenues from those contracts must be treated as off-system sales under the FAC and shared with ratepayers.[288] Both Staff and OPC were highly critical of treating the costs that way for a customer the size of Noranda.[289] If OPC, or any party for that matter, insisted on a jurisdictional allocation of costs to serve Noranda, the effect would be to deprive Noranda of any effective rate relief whatsoever.

The Commission's authority to permit Ameren Missouri to have a fuel adjustment clause ("FAC") is § 386.266 RSMo. This statute allows rates to be adjusted outside of general rate cases in order for the utility to recover its cost of "fuel and purchased power." This statute does NOT authorize Ameren Missouri to impose upon ratepayers non-fuel costs associated with off-system.[290] The Commission is a creature of Missouri statutes and only has the powers authorized

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Matter of the Cancellation of the Certificate of Convenience and Necessity of Envirowater Company, LLC, Tariff No. YS-2004-14011.

[287] Kliethermes Surrebuttal, Ex. 222, p. 27, ll. 9-17, Appendix pp. 1-2 – 1-5; Dauphinais testimony. Tr. p. 2795, l. 21 – p. 2796, l. 22; Mantle testimony, Tr. p. 3037, l. 10 – p. 3040, l. 3.

[288] Kliethermes Surrebuttal, Ex. 222, Appendix pp. 1-4 – 1-5.

[289] Kliethermes Surrebuttal, Ex. 222, Appendix pp. 1-4 – 1-5; Mantle Surrebuttal, Ex. 402, p. 16, l. 14 – p. 23, l. 13.

[290] *See* § 386.266

by statute. Thus any Commission rules or tariffs pertaining to the FAC which are not authorized by this statute are unlawful.

Under specified circumstances the Commission's rules allow the FAC to include a mechanism to flow through the FAC a credit to ratepayers for "prudently incurred fuel and purchased power costs associated with the electric utility's off-system sales,"[291] and Ameren Missouri's FAC tariff provides for the inclusion of such revenues and costs in the calculation.[292] But purchased power costs form only a portion of the costs that Ameren Missouri would incur in providing wholesale service to Noranda. Neither the Commission's regulation nor Ameren Missouri's tariff expressly address how such costs should be allocated. Moreover, the Commission Staff has raised a number of concerns relating to including the fuel and purchased power costs associated with the transaction in the FAC, including the need to allocate costs associated with any wholesale contract with Noranda pursuant to a wholesale jurisdictional allocation.[293] Given the magnitude of the costs associated with the proposed transaction and the uncertainties surrounding their allocation, Ameren Missouri proposal is not tenable. This uncertainty creates a high risk that the New Madrid smelter would be without a source of power for future operations, to the detriment of Noranda, other ratepayers and Missouri's economy.

(d) <u>Ameren Missouri Has Never Made Any Valid Settlement Proposal to Noranda</u>

Ameren Missouri's statements on the record of the hearing in this case regarding settlement discussions compel Noranda to set the record straight. Ameren Missouri's counsel stated in her opening statement on this issue that Noranda's management "wasn't interested in

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[291] CSR § 240-20.090(1)(B)(2).

[292] *See, In the Matter of the Adjustment of Union Electric Company, d/b/a Ameren Missouri's Tariff*, Report and Order in Case No. ER-2012-0166, on page 76-77.

[293] S. Kliethermes Surrebuttal, Ex. 222, Appendix 1-3 – 1-7.

pursuing" a wholesale proposal and that "if I were someone who had a fiduciary duty to that company I would have explored it very carefully."[294] It might appear from Ameren Missouri's characterization of settlement negotiations that Noranda was not interested in a proposal that someone with a fiduciary duty would explore very carefully. To the contrary, Noranda indeed was interested in exploring any valid and fair proposal with Ameren Missouri if a valid proposal had been offered, but Ameren Missouri offer no such proposal at all. Noranda invested months of time and financial resources in several months of settlement efforts with Ameren Missouri in this case and indeed for months prior to this case.[295] Noranda also sought to settle revenue requirement issues in this case with Ameren Missouri, engaged in extensive settlement discussions and made several offers on major revenue requirement issues which were rejected by Ameren Missouri.

Ameren Missouri never made any lawful or valid proposal to Noranda. Ameren Missouri's "proposal" was at best half-baked, and at worst specious. Ameren Missouri's "proposal" failed to include essential terms – for example, there was no price term and no provision regarding creation of how a legal wholesale structure could even be created. Ameren Missouri may have concluded that it served its shareholders' interest by appearing to the Commission and the parties to this case that is was trying to work on a "solution" for Noranda[296] but its actions evidenced no actual intention of doing so. Indeed, Ameren Missouri's "proposal" seems to have been designed by Ameren Missouri to terminate the CCN and its legal obligation

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[294] Tr. pp. 2348-2387.

[295] Noranda's CEO Kip Smith personally participated in eight in-person meetings with Ameren Missouri's CEO Michael Moehn from October, 2014 through February, 2015. Seven of those meetings were held at Ameren Missouri's office in St. Louis, for which Mr. Smith traveled to St. Louis. In addition, Noranda invested several hundred hours of its legal and expert time in negotiations and research including retention of FERC counsel in efforts to uncover and "fix" severe flaws in Ameren Missouri's various iterations of its proposals, such as missing terms. Ameren Missouri's statement that Noranda "walked away from table" is, to say the least, disingenuous.

[296] Michels Testimony, Tr. pp. 2928-3073.

to serve Noranda, thus removing Noranda from the Commission's jurisdiction and the Missouri regulatory process. As shown by the evidence of the non-Ameren Missouri parties to this case, this "heads Ameren wins tails ratepayers lose" scheme would deprive ratepayers of the benefit of the bargain struck by their Stipulation in the CCN in Case No. EA-20015-0180 ((including the Commission's authorization of the Metro East Transfer so vigorously sought by Ameren Missouri in the CCN proceeding), and would be detrimental to the public interest.

IV. QUESTIONS RAISED BY COMMISSIONER HALL[297]

A. What is the Risk Concern That Ameren and Noranda Have Concerning the Wholesale Agreement Proposal That Ameren Put Forth?

Major risk concerns are (1) that wholesale agreement cannot be enforced, thus jeopardizing Noranda's supply of reliable power and causing the New Madrid smelter to go out of business; (2) that the wholesale agreement would require Noranda to relinquish its right to its electric supply by causing termination of the Certificate of Convenience and Necessity granted by the Commission in Case No. EA-2005-0180; and (3) that the wholesale agreement would remove service to Noranda from Commission jurisdiction causing Noranda to lose the right to assured power supply and reliability protection essential to the survival of the New Madrid smelter. See extensive discussion of this issue in Section III(M) and (N).

1. To What Extent Can the Commission in an Order or Tariff Mitigate or Eliminate That Risk?

Noranda and the MIEC do not believe it is possible for the Commission to mitigate or eliminate these risks.

2. To What Extent Can the General Assembly Mitigate or Eliminate That Risk?

[297] During the evidentiary hearing on March 12, Commissioner Hall asked the parties to address four questions in their briefs.

Noranda and the MIEC do not believe it is possible for the General Assembly to mitigate or eliminate that risk.

B. How and to What Extent Would Ratepayers be Harmed By Moving Noranda to Wholesale Service?

Ratepayers would be harmed because their rates would increase due to the loss of the Noranda's contributions to Ameren Missouri's fixed costs and system stability. Ratepayers would also be harmed by the severe damage to Missouri's economy that would result from the loss of Noranda's contributions to Missouri's economy. See extensive discussion of this issue in Section III(M) and (N).

C. What Would Be the Effect on Ameren and Its Customers of Eliminating the 12 (M) Adjustment of Off-system Sales in the Current FAC Tariff? Is it Appropriate to Do So?

Ameren Missouri's tariff no longer refers to the term "N Factor" .

Ameren Missouri's current FAC tariff permits the recovery of OSSR revenues to the extent the load at Noranda decreases by 40,000,000 kwhs in a month. The clause says that Ameren Missouri is entitled to recover the **lesser** of the following:

1. **The Revenues From the Loss of Load For That Month, or**

2. **The Level of Normalized Revenues That Should Have Been Collected As Determined in The Rate Case.**

The risk if this clause is removed lies squarely on Ameren Missouri. If the clause is not present, then if Noranda would leave the system, the revenues from all additional Off System sales would flow through the FAC and benefit customers 95% and Ameren Missouri 5%.

Noranda and the MIEC note that the "N Factor" was originally approved for Acts of God and was not intended to cover any and all loss of load possibilities. Clearly under the current clause, Ameren Missouri is given substantial risk protection.

D. <u>Assuming that the AAO is 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?</u>

The legal basis for denying recovery of these amounts is the Missouri Supreme Court's decision in the UCCM case, as discussed in the section of this brief addressing this issue. See extensive discussion of this issue in Section I(D).

Respectfully submitted,

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CERTIFICATE OF SERVICE

I do hereby certify that a true and correct copy of the foregoing document has been emailed this 31st day of March, 2015, to all counsel of record.

/s/ Diana M. Vuylsteke