BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers In the Company's Missouri Service Area.	))))	**Case No. ER-2010-0036**

AMERENUE'S STATEMENTS OF POSITION

COMES NOW Union Electric Company d/b/a AmerenUE (AmerenUE or Company), and in accordance with the Missouri Public Service Commission's *Order Adopting Procedural Schedule and Establishing Test Year*, hereby provides its Statement of Position on each of the disputed issues in this case.

1. Overview and Policy: Overview of "cost of service" and/or what policy considerations, if any, should guide the Commission in deciding this case?

In this filing, AmerenUE asks the Commission to issue an order that:

- Allows AmerenUE to recover the revenue requirement associated with significant capital costs it has already incurred to provide service to its customers, to recover a reasonable level of operating expenses and to provide it with a fair opportunity to earn returns commensurate with what other integrated electric utilities are allowed to earn; and
- Takes steps to reduce the excessive regulatory lag the Company faces, including addressing the important policy implications of excessive regulatory lag.

Consistent with its customers' expectations and initiatives adopted by this Commission (including vegetation management, infrastructure inspection and repair and reliability rules), the Company has made significant levels of capital investment (approximately $650 million just since the true-up cutoff date in the Company's last rate case) in its energy infrastructure. These investments are serving customers – today. The Company's reliability and power plant performance are in the top quartile nationally. The Company's rates are the lowest among all investor-owned utilities in the state (and will remain so after this case) and are among the lowest in the entire country.

If customer expectations are to continue to be met, if the kinds of investments the Company would like to make to maintain or improve on its reliability and power plant performance are to continue to be made, the Company must receive consistent, constructive regulatory treatment. The Company recognizes that no time is a good time to ask for a rate increase, and that the existing and recent economic environment is particularly challenging for our customers. In light of those concerns, the Company has made disciplined reductions in its planned investments, and has taken other cost-cutting measures, which will be reflected in the trued-up revenue requirement in this case.

But the bottom line is that the Company has not had a reasonable opportunity to earn a fair return on equity for some time now, and must have a rate increase to at least improve that opportunity. Over the past 32 months the Company has, on average, fallen short of its allowed return on equity by more than 200 basis points. Over the last 12 months, that shortfall has exceeded 400 basis points (after taking into account the Company's absorption of the impact of the Taum Sauk Plant being out of service). The Company's negative free cash flow has been approximately $1.3 billion over the past three years. These financial realities have required the Company to eliminate worthwhile capital projects. And these financial realities exist despite the fact the Company has filed three rate cases within a span of less than 37 months.

In this case the Company is requesting an allowed return on equity of 10.8%, which is in line with the allowed return on equity approved just one year ago, and within just 20 basis points of the national average allowed return on equity for integrated electric utilities in the recent past. Given the Company's chronic inability to earn its allowed return on equity in the face of its investment needs, and its risk, this return on equity is reasonable and appropriate. Moreover, the Commission should provide mainstream rate treatment, consistent with other jurisdictions, with regard to establishing a return on equity for the Company and for depreciation rates. Mainstream treatment in these areas is critical to permit AmerenUE to compete with other utilities to access the capital it needs to invest in its system.

The Company is seeking to continue vegetation management and infrastructure inspection trackers that were approved just one year ago. The Company is asking to implement just one additional tracker to track storm costs, which are unpredictable, volatile, and completely beyond the Company's control. No party is harmed by these trackers, but they help reduce regulatory lag and are appropriate for these kinds of expenditures. With regard to the Company's fuel adjustment clause, the continuation of which no party challenges, it is critical that there be no change to its pass-through mechanism, which is already out-of-the-mainstream, and which is entirely unnecessary for AmerenUE to have the incentive to properly manage its net fuel costs. Indeed, there is no evidence in this case that the operation of AmerenUE's fuel adjustment clause has caused it to change its practices regarding fuel and purchased power procurement or off-system sales, the evidence shows that the Company's power plants continue to operate reliably and efficiently, and no facts or circumstances have changed in the past year in a manner that would suggest that the sharing percentage should be changed.

In summary, it is critically important to the Company, to its customers, to the thousands of employees and contractors whose employment depends on the Company, and to the state, that the Company receive constructive and consistent regulatory treatment so that it can effectively compete for capital at a reasonable cost, and so that it can continue to deliver the top-quartile service its customers expect. The specific issues in this case must be viewed in the context of this over-arching policy consideration.

2. **Return on Equity: What return on equity should be used in determining AmerenUE's revenue requirement?**

The Commission should adopt a 10.8% return on equity (ROE) based on the updated recommendation contained in the rebuttal testimony of Dr. Roger Morin. This is the median of the results of the seven studies performed by Dr. Morin. This is a conservative recommendation because:

(a) the Company's exposure to regulatory lag is significant, and as a result of regulatory lag the Company has been unable to earn anywhere close to its authorized return on equity for several years, and for more than a year has been earning approximately 400 basis points below its authorized return on equity; and

(b) The Company's significant reliance on coal-fired generation compared to the industry average creates increased risk that the Company will have to make significant capital investments.

Dr. Morin's recommendation is also reasonable because it is close to the national average of return on equities authorized for integrated electric utilities of 10.59% in 2009. The returns on equity authorized for integrated electric utilities by other state commissions should be considered because AmerenUE competes for capital with utilities operating in other states. Indeed, under the established principles enunciated in the Supreme Court's decisions in the *Hope* and *Bluefield* cases, the Commission has a legal obligation to set the Company's allowed ROE so that the "return to the equity owner . . . [is] commensurate with returns on investments in other enterprises having corresponding risks." *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 503 (1944) (citations omitted).

The 9.35% recommendation of the Staff should be completely disregarded by the Commission. Indeed, it is nowhere near allowed ROEs for enterprises (integrated electric utilities) with corresponding risk to that of AmerenUE. The Staff has made errors in its analysis, disregarded the results of its constant growth discounted cash flow (DCF) analysis, and selected unsupported and unreasonable inputs for its analyses. The Staff has attempted to confirm the reasonableness of its recommendation using unusual and inappropriate data. Staff's recommended ROE is approximately 125 basis points below the national average for returns on equity for integrated electric utilities, and it is outside the "zone of reasonableness" established by the Commission in previous cases. As a consequence, the Commission should reject the Staff's recommended ROE.

The ROE's recommended by Mr. Gorman and Mr. Lawson should be adjusted to reflect more reasonable choices of methodologies and inputs. As adjusted, these recommendations would be similar to Dr. Morin's.

What capital structure should be used for determining AmerenUE's revenue requirement? (True-up Issue)

The Company's actual capital structure as of the true-up cutoff date should be used to determine the revenue requirement in this case. That actual capital structure, consisting of 51.12 percent common equity is quite comparable to the capital structure used to set the revenue requirement in the Company's last rate case (where common equity comprised 52 percent of the capital structure).

How should flotation costs be reflected in determining AmerenUE's revenue requirement?

The actual flotation costs associated with the $436 million equity infusion on September 28, 2009, which total $13,703,966, should be amortized over 5 years as recommended by the Commission Staff and the Office of the Public Counsel. This is consistent with the Commission's past decisions to treat flotation costs as an expense, and is consistent with a recent settlement of the same issue in an ***Empire*** case, where flotation costs were also amortized over a 5-year period. To ensure that these legitimate flotation costs are fully recovered and in recognition of the time value of money, the unamortized portion of the flotation costs should be included in rate base. MIEC witness Gorman's position that the flotation costs should be reflected in the Company's capital structure is inconsistent with the Commission's treatment of these costs as an expense and should be rejected.

3. Vegetation Management Expense

i. What level of vegetation management expense is appropriate for recognition in AmerenUE's revenue requirement?

Because the Company is still ramping up its efforts to comply with the Commission's vegetation management rules, the Commission should follow the approach it adopted in the Company's last rate case; that is, the Commission should use the average of its 2010 and 2011 budgets, which is $53.7 million for vegetation management. If the Commission does not continue the tracker mechanisms, then the amount in AmerenUE's revenue requirement should be set at the level of AmerenUE's 2010 budget, as the Company will be required to spend more in 2010 than it spent in 2009 on these requirements. That level is $52.9 million for vegetation management.

ii. Should a tracker continue to be implemented for AmerenUE's vegetation management expense that varies from the level of vegetation management expense the Commission recognizes in AmerenUE's revenue requirement?

Yes, the Commission should continue the tracker it approved just one year ago in Case No. ER-2008-0318. The reasons set forth in the Report and Order in that case for the Commission's approval of this tracker have not changed. It is still an uncertain cost which the Commission's rules impose upon the Company. AmerenUE has worked very hard to meet (and has met) the more stringent standards of the Commission's vegetation management rules, yet almost 60% of our circuit miles had not been trimmed under these new requirements as of February of this year. Other parties argue the Company has enough experience to know what the costs will be, but AmerenUE disagrees. While the Company had previously been working toward trimming its circuits on a 4- (urban) and 6- (rural) year cycle, that work was done using a less rigorous standard than is contained in the Commission's rules. That experience cannot be relied upon to set the cost of compliance going forward. Without the tracker, it is the Company that bears the risk if maintaining compliance forces AmerenUE to spend more than is put into the revenue requirement. The use of a tracker is the fairest way to ensure that the Company recovers the cost of compliance without imposing a risk of an under-recovery of expenditures the Company is required to make, or imposing the risk of recovering too much money from our customers. Neither outcome is desired and only the tracker ensures that neither will occur.

4. Infrastructure Inspection Expense

i. What level of infrastructure inspection expense is appropriate for recognition in AmerenUE's revenue requirement?

Because the Company is still ramping up its efforts to comply with the Commission's infrastructure inspection rules, the Commission should follow the approach it adopted in the Company's last rate case; that is, the Commission should use the average of its 2010 and 2011 budgets, which is $8.9 million for infrastructure inspection. If the Commission does not continue the tracker mechanism, then the amount in AmerenUE's revenue requirement should be set at the level of AmerenUE's 2010 budget, as the Company will be required to spend more in 2010 than it spent in 2009 on these requirements. That level is $8.8 million for infrastructure inspection.

ii. Should a tracker continue to be implemented for AmerenUE's infrastructure inspection expense that varies from the level of infrastructure inspection expense the Commission recognizes in AmerenUE's revenue requirement?

Yes, because there is no reason to believe that AmerenUE's experience with its new infrastructure inspection programs can be used to set an appropriate amount for infrastructure inspection in the Company's revenue requirement. Prior to the effective date of the infrastructure inspection rule, AmerenUE did not have programs that inspected facilities in the manner it is now required to do. AmerenUE has just over a year's experience with the underground, streetlight and overhead facility inspection requirements. AmerenUE's programs have yet to reach maturity, so that the Company can be reasonably assured that it knows the amount it will spend on compliance going forward. The Commission should continue its practice of encouraging the Company to meet these requirements by allowing an amount in rates that is likely to match the actual expenditures. The best way to do that, and to protect all parties involved, is to continue the tracker for AmerenUE's infrastructure inspection costs.

5. Storm Expense

i. What level of storm expense is appropriate for recognition in AmerenUE's revenue requirement?

The Commission should include $10.4 million in the Company's revenue requirement for storm restoration efforts, which is the amount of expense incurred during the test year. Historically, expenditures over and above those included in rates are either captured in the test year and amortized over five years or in an accounting authority order and held until the next rate case and then amortized over five years. Of course, neither option ensures cost recovery. The fact that these amortizations have consistently been necessary over the past several years indicates the amount in the revenue requirement is insufficient for the work the Company is expected to complete. Setting the amount in the Company's revenue requirement to a higher level will make it less likely that AmerenUE will be faced with making an expenditure that it may not be able to fully recover or that will necessitate yet another accounting authority order.

ii. Should a tracker be implemented for storm expense that varies from the level of storm expense the Commission recognizes in AmerenUE's revenue requirement?

Yes, a tracker should be implemented because it is in the best interest of all parties. While the Company is sensitive to the concern that not every cost be placed into a tracker, storm restoration expenses are unlike many other operational expenses the Company incurs. AmerenUE has no control over when or where a major storm will hit its system. However, once that storm has left our customers without power, the Company is expected to restore service as quickly as possible. We believe that our customers and this Commission expect it. AmerenUE has improved its response to major storms over the past several years and believes the Commission and our customers recognize that improvement. There is a cost behind that improvement; storm restoration efforts can result in significant expenditures that often exceed the amount in the Company's revenue requirement. Of course, storms are unpredictable and neither the Commission not the Company knows for sure if or when a major outage will occur. Since the Company is asking the Commission to raise the amount in its revenue requirement significantly, a tracker offers the appropriate protection for our customers, to ensure there is not an overcollection of these expenditures.

iii. Should the amount incurred during the test year, in excess of the level of storm expense that is appropriate for recognition in AmerenUE's revenue requirement be amortized?

It should. AmerenUE experienced a devastating storm in the southeastern portion of its service territory in January of 2009. 36,500 customers lost power, which is 95% of all of the Company's customers in that region. The Company lost 3,800 poles and many counties had no electricity at all. AmerenUE was forced to rebuild much of its subtransmission system. The Company undertook a massive effort to restore service to our customers. Despite the terrible weather and the daunting logistical challenges presented by this storm, AmerenUE was able to restore service to its impacted customers much faster than the surrounding electric cooperatives.

Most of the cost of the January 2009 storm were capital costs. However, $7.8 million was spent on O&M, which is more than the amount included for storm restoration costs in AmerenUE's last rate case. No one has challenged the prudency of these expenditures. AmerenUE believes the Commission should allow the Company to amortize the difference. Staff witness Stephen Rackers supports this treatment of those costs.

6. Power Plant Maintenance Expense: What level of plant maintenance expense for the coal-fired generating units is appropriate for recognition in AmerenUE's revenue requirement?

The test year level of plant maintenance should be included in the revenue requirement in this case. The test year is a period past that is employed as a vehicle upon which to project experience in a future period when the rates determined in the rate case at issue will be in effect. *See, e.g., State ex rel. Mo. Power & Light Co. v. Pub. Serv. Comm'n*, 669 S.W.2d 941, 945 (Mo. App. W.D. 1984). Rates from this rate case are expected to take effect in June 2010. Because of the need to place the scrubbers being installed at the Sioux Plant into rate base and for other reasons (e.g., to rate base the continued high level of investments the Company is making in its energy infrastructure), it is extremely likely that another rate case will be filed later in 2010 or early in 2011. Consequently, it is very likely that rates set in this case will remain in effect no longer than up to approximately 18 months (from June 2010 to no later than late 2011). Both the Staff and MIEC propose to "normalize" power plant maintenance expense. However, normalization should only occur with regard to a revenue or expense item where the "actual cost incurred in the test year is not representative" of the expected cost during the period when rates are to be in effect. *Id.*

MIEC proposes to "normalize" power plant maintenance expenses by reducing the test year amount of approximately $118.9 million to $105 million. The Staff proposes to "normalize" the expense by reducing the test year amount to approximately $101.1 million. Both normalizations are inappropriate and will not reflect a representative level of power plant maintenance expense when rates are expected to be in effect in this case. MIEC examined expenses generally in the 2004 to 2009 time-frame (and in one instance, the budgeted amount for 2010). In doing so, MIEC failed to account for the undisputed fact that a dollar in 2010 simply isn't worth as much as a dollar in 2004, 2005, etc.

As discussed below, the Company has budgeted $117.5 million (nearly as much as the test year level) for 2010, and indeed a major scheduled outage at one of its largest plants, the Rush Island Plant, is well underway and is scheduled to be complete by mid-April. A smaller but still significant outage at its Meramec Plant has already been completed, and further scheduled outage work will be done at the Sioux Plant when the scrubbers at Sioux are placed in service.[1] During most of the period of time relied upon by MIEC, the Company was performing an abnormally low number of scheduled outages (just 1.875 per year, on average) versus approximately three per year in the early 2000s, two and one-half planned in 2010, and three and one-half planned in 2011. As explained in the rebuttal testimony of AmerenUE witness Mark C. Birk, during 2005 to 2008 the Company was transitioning from shorter intervals between scheduled outages at its 12 steam units (located at its four plant sites) to longer intervals, which temporarily reduced the number of scheduled outages during the transition period. This makes the expense levels in 2005 through 2008 (relied on by MIEC and in part by the Staff) unrepresentative. Moreover, for 2009 the Company had to defer proceeding with scheduled outages that it had originally planned to take in 2009 to conserve cash driving the financial crisis. This also makes 2009 expense levels unrepresentative.

[1] Although this substantial work is and has already occurred in 2010, the power plant maintenance expense in rates at this moment is just $91.1 million, which is already failing to cover the Company's costs.

The Staff's proposed adjustment should be rejected for similar reasons, that is, because the Staff did not take the time value of money into account, and because the Staff used data when an abnormally low number of scheduled outages were taken. The Staff "normalized" power plant maintenance expense by taking a simple average of three, 12-month periods: the 12 months ending March 31, 2007, 2008, and 2009. The problem with the Staff's use of these figures is that it includes the abnormal period when the Company was taking less scheduled outages than normal. Over the three year period examined, the Company had just four scheduled outages – only 1.33 per year. During the first two years of that period the Company had just approximately two scheduled outages, or just one per year.[2] A normal level of outages is two to three per year, as planned in 2010 and 2011, when rates in the case are expected to remain in effect.

Spending the money that needs to be spent to maintain these coal-fired units is critically important if the Company is to be able to continue to maintain the high level of equivalent availability it (and its customers) have enjoyed for the past several years. That high equivalent availability allows the Company to make more off-system sales, which in turn lowers the net fuel costs tracked in the Company's fuel adjustment clause. Moreover, more optimal maintenance of the plants makes them run more efficiently, which reduces fuel consumption which in turn reduces fuel expense, which also benefits customers immediately through the fuel adjustment clause. Failure to provide in rates a normal level of expense will put the Company in the position of having to make very difficult choices regarding its power plant maintenance expense levels, which may include a need to reduce those expenditures. Eventually, lowering those expense levels

[2] The Company commenced a scheduled outage at Labadie Unit 1 in March 2008, but did not complete it until May 27, 2008 – outside the two year period at issue.

will negatively impact equivalent availability and plant efficiency, leading to higher, not lower net fuel costs. The Staff's and MIEC's "normalization" adjustments should be rejected.

7. Rate Case expense: What level of rate case expense is appropriate for recognition in AmerenUE's revenue requirement?

The expenditures made by AmerenUE for this rate case are prudent and should be recovered. While there have been assertions that portions of AmerenUE's rate case expense should not be allowed, no party has provided the Commission with sufficient justification to disallow any of these expenditures.

Staff's position is that this expense should be capped at a $1 million. This cap is based on Kansas City Power and Light's rate case expenditures. Of course, there are completely different issues in AmerenUE's case with different levels of complexity of issues and a different number of parties involved. Merely presuming we should spend a similar amount has no basis and should be rejected by the Commission.

OPC takes the position that AmerenUE should not be allowed to use external attorneys or external witnesses for multi-million dollar issues such as Return on Equity. OPC also proposes splitting prudent expenditures 50/50 between the Company's shareholders and customers. Both of these recommendations should be rejected. First, both of those recommendations are based on bare, unsupported assertions by OPC that establish no imprudence regarding any of AmerenUE's rate case expense. There is no evidence that AmerenUE employs enough attorneys who are available to prosecute this rate case. OPC distorts the answer to the question of which attorneys have regulatory experience and wrongly assume that other Ameren attorneys are available to assist AmerenUE in this case. They are not. They all have full time jobs representing the

Company or an affiliate before other regulatory bodies. AmerenUE hires external attorneys as the need for additional legal support arises. It is most likely to arise during rate cases, which are very time consuming. The same applies to OPC's assertion that other employees at the Company could provide Rate of Return testimony. The employees listed in a data request answer provided to OPC have provided some testimony in the past, but now are unavailable because of current job responsibilities. None of the individuals listed in the data request answer have the depth of experience of Dr. Morin. All of AmerenUE's rate case expenditures are prudent and the Company should be given the opportunity to recover those expenditures through its rates.

8. Callaway Fuel/Fuel Modeling Issues: What is the appropriate nuclear fuel price input for the production cost model?

The appropriate nuclear fuel cost input for the production cost model is the nuclear fuel price associated with the nuclear fuel that was bought and paid for, and delivered to the Callaway Plant site well before the January 31, 2010 true-up cutoff date in this case. As outlined in detail in the rebuttal testimony of AmerenUE witness Randall J. Irwin, these nuclear fuel costs are known and measurable as of the true-up cutoff date in this case. The fuel at issue will be fully loaded into the Callaway Plant's reactor and will be generating electricity before rates to be set in this case take effect. Including these known and measurable nuclear fuel costs in rates in this case much more accurately rebases the Company's net fuel costs through the Company's fuel adjustment clause. Indeed, the Staff's opposition to including these known and measurable nuclear fuel costs in rates in this case appears to be at odds with the Staff's criticism of other utilities for, in the Staff's view, not taking as much care in properly rebasing its net fuel costs with a fuel adjustment clause. To the contrary, the Company has taken great care to properly rebase its net fuel costs (see the Rebuttal Testimony Regarding the Fuel Adjustment Clause of AmerenUE witness Timothy D. Finnell), including these known and measurable nuclear fuel costs.

9. Other Fuel Model Issues:

i. What are the appropriate market energy prices to be used as inputs for the production cost model?

The appropriate market energy prices to be used as inputs for the production cost model are those based upon the Midwest Independent Transmission System Operator, Inc.'s (MISO) Day-Ahead hourly market prices, as discussed in detail in the surrebuttal testimony of AmerenUE witness Timothy D. Finnell. The market prices discussed in the supplemental rebuttal testimony of Staff witness Erin Maloney inappropriately include bilateral sales made using power from the now-expired Arkansas Power & Light Company purchased power agreement, block sales that are not representative of normalized hourly market prices, and improperly mix MISO day-ahead and real-time prices.

Moreover, the additional adjustment to account for load and generation forecasting errors discussed in Mr. Finnell's direct testimony must be made. Values for revenue sufficiency guaranty payments for the three years ending with the true-up cutoff date should be used to determine the adjustments needed for the load and generation forecasting errors.[3]

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[3] While a true-up issue, the hedged power sales put into place prior to the true-up cutoff date in this case, which are a normal part of AmerenUE's off-system sales, should also be included in the production cost modeling that underlies the true-up net fuel costs in this case.

iii. What is the appropriate Callaway refueling outage period to be used as an input for the production cost model?

Having reviewed MIEC witness James Dauphinais' surrebuttal testimony, the Company agrees that it is appropriate to use 36 days as a normalized Callaway Plant refueling outage period as an input for the production cost model. This means that 24 days (2/3 of a refueling outage, given that refueling outages occur every 18 months) should be used in the production cost modeling.

10. Fuel Adjustment Clause (FAC):

i. Should the Commission discontinue AmerenUE's fuel adjustment clause, or should the Commission modify AmerenUE's fuel adjustment clause?

AmerenUE's fuel adjustment clause (FAC) should be continued. Indeed, no party has suggested or recommended that AmerenUE's FAC be discontinued, and there has been no change in any fact or circumstance since the fuel adjustment clause was approved approximately one year ago that would warrant discontinuance. In fact, the fuel adjustment clause is more important than ever, and is absolutely necessary for AmerenUE to have any chance to earn its authorized return on equity. The Commission found that to be true in its Report and Order in the Company's last rate case, and it is even more true today as evidenced by the fact that AmerenUE's earned rate of return has fallen far short of its authorized return. Without a fuel adjustment clause its earned returns would have been even worse.

In addition to the fact that the fuel adjustment clause remains absolutely necessary for AmerenUE to have any reasonable opportunity to earn a fair return on equity, the three factors historically considered by the Commission in determining whether an FAC is appropriate for tracking fuel costs continue to support continuation of the FAC. Those factors are as follows:

1. The costs/revenues to be tracked are substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases;
2. The costs/revenues to be tracked are beyond the control of management, where utility management has little influence over experienced revenue or cost levels; and
3. The costs/revenues to be tracked are volatile in amount, causing significant swings in income and cash flows if not tracked.

First, AmerenUE's net fuel costs (fuel and purchased power costs net of off-system sales revenues), which are tracked in the FAC, are clearly substantial enough to have a material impact upon revenue requirements and financial performance if not tracked. AmerenUE's fuel and purchased power costs represent the Company's largest operating and maintenance (O&M) expense—approximately 47% of the Company's total O&M expenses. The Company's net fuel costs have increased substantially since the last rate case, rising from $322.5 million to over $500 million.

Second, the components of the Company's net fuel costs remain beyond the control of management. The Company's ability to control fuel and power prices established in national and international markets is non-existent.

Third, the volatility of these costs and revenues has only increased since the last rate case, as evidenced by the significant decline in the Company's net fuel costs.

Retention of AmerenUE's FAC is also critical to AmerenUE's ability to maintain its credit quality, and to stay on par with 90% of integrated electric utilities across the country that have an FAC, including the two other electric utilities in Missouri that are eligible to have an FAC. Finally, elimination of AmerenUE's fuel adjustment clause only one year after it was first approved (and before even one recovery cycle or prudence review has been completed) is unjustified and suggests a level of regulatory instability that is not helpful to Missouri's regulated utilities.

AmerenUE's fuel adjustment clause should be modified in the manner reflected in the First Non-Unanimous Stipulation and Agreement filed with the Commission on March 10, 2010.

ii. If the Commission modifies AmerenUE's fuel adjustment clause what percentage of the difference between actual fuel and purchased power costs, net of off-system sales and the cost included in base rates should the Commission adopt for recovery through the fuel adjustment clause?

The sharing percentage should be 95%/5%. A 95%/5% sharing percentage is consistent with that approved for other Missouri utilities with fuel adjustment clauses, and indeed the majority of fuel adjustment clauses in use around the country contain no sharing at all. In addition, in a rising cost environment, sharing is tantamount to a cost disallowance for a utility. AmerenUE's potential under-recovery of prudent fuel expenses should not be increased from the current 5% level. Finally, the sharing percentage should not be increased because AmerenUE has demonstrated over the past year that it has a sufficient incentive to operate its plants efficiently and manage its net fuel costs prudently. AmerenUE's generating plants' equivalent availability improved in

2009 over 2008 (creating the opportunity for more off-system sales), and the Company has retained its sophisticated fuel purchasing and hedging strategies.

iii. Should the revenues from long-term bilateral contract sales flow through AmerenUE's fuel adjustment clause? If so, how?

The Company is agreeable to the additional FAC tariff modification proposed in the surrebuttal testimony regarding the FAC of Staff witness Lena Mantle *so long as* the costs associated with the contracts, which under Ms. Mantle's proposal would be treated as off-system sales, are properly allocated to retail ratepayers whose net fuel costs will be lowered substantially as a result of receiving the revenues under those contracts through the FAC.[4] Otherwise, retail ratepayers would receive revenues, but would fail to pay the costs associated with producing those revenues.

iv. Additional FAC concerns

Aside from the merits of retaining its FAC, AmerenUE is concerned about the way this issue was raised in this proceeding. As the Commission may know, all of the parties to this case, in compliance with the Commission's prior orders, jointly filed a proposed procedural schedule with the Commission near the beginning of the case. Pursuant to the terms of that proposed procedural schedule, all testimony relating to changes to AmerenUE's fuel adjustment clause, including structure, terms and continuation of the fuel adjustment clause, were to be filed by December 18, 2009, when the direct testimony of non-AmerenUE parties concerning the Company's revenue requirement was due. This schedule was approved by the Commission and the parties, including AmerenUE, relied on it.

[4] AmerenUE would also propose that contracts to supply power to Missouri municipalities continue to be excluded from off-system sales, as has been the case for many years, including a continuation of the allocation of the costs associated with those municipal contracts away from retail ratepayers.

No party filed any testimony opposing the continuation of the FAC or criticizing any material provision of AmerenUE's FAC in either their direct testimony on December 18, 2009 or in their rebuttal testimony filed weeks later. Late in the case the Commission issued its order changing the approved schedule and inviting the parties to file additional direct, rebuttal and surrebuttal testimony concerning AmerenUE's FAC. Under the terms of the revised schedule, AmerenUE had just four days to respond to testimony proposing major changes to its fuel adjustment clause which, if adopted, would likely cause AmerenUE to absorb millions, or even tens of millions, of dollars in prudently incurred net fuel costs.

AmerenUE is aware that when a rate case is filed it is required to request continuation of its FAC, and must file extensive minimum filing requirements and testimony to support its request. AmerenUE did so. AmerenUE is also aware that other parties have a right to file testimony regarding the continuation of the FAC, or possible modifications. All parties had many months to do so. AmerenUE's concern stems from the creation of a contested issue three-fourths of the way through this rate case when in fact there was no testimony about the issue, and the resulting potential for unfairness in the rate case process that the late injection of this issue into the case creates.

11. Executive Compensation: What level of executive compensation is appropriate for recognition in AmerenUE's revenue requirement?

The salaries of its top five executives, just like the salaries of other AmerenUE employees, should be reflected in the Company's revenue requirement. The compensation programs of AmerenUE's executives are prudent and aligned with the market. No party in this case alleged otherwise. AmerenUE's executive leadership sets AmerenUE's strategy and creates value for all of its stakeholders – especially our customers. No one has argued that these roles are not necessary or important. The salaries paid to AmerenUE executives are market competitive, appropriate and a normal cost of doing business.

12. Depreciation Expense:

i. Should depreciation rates for the Company's steam production and hydroelectric power plants be established using the life span approach or the mass property approach?

The life span approach should be used. The Company's existing composite depreciation rates are barely above the 13th percentile nationally. That fact alone suggests a problem in the approach taken in the past (largely past adoption of the Staff's mass property depreciation rates). The Staff's recommended depreciation rates in this case are only marginally above the Company's current rates. MIEC's proposal would be far, far worse - -the Company's composite depreciation rates would nearly be "off-the-chart"; well below the 10th percentile. The Company's proposal would move the Company's composite depreciation rates up to just above the 33rd percentile, which is still relatively low.

A key reason why the current rates (and the Staff's proposed rates) are far too low arises from the Staff's stubborn refusal to use the well-accepted, mainstream life span approach to setting depreciation rates for AmerenUE's steam production plants. The life span approach, used in virtually every other jurisdiction in the country and which is based on the use of informed estimates of the final retirement date of each of the Company's four steam production plants, should be used to set depreciation rates for those steam production plants in this case. Staff's refusal to use the life span approach for non-nuclear production plant makes no sense in light of the Commission's own regulations (4

CSR 240-3.175, Submission Requirements for Electric Utility Depreciation Studies), which requires that Missouri electric utilities provide an estimated date of final retirement for each warehouse, electric generating facility, combustion turbine, general office building or other large structure. The steam production plants are classic examples of life span property, and all authoritative texts and reference materials (and the Commission's own regulations) treat them as such. The Staff incorrectly argues that the Commission has "rejected" the life span approach, yet the Staff's depreciation expert admitted in deposition that this is not the case. Rather, the Commission simply found far different and less sufficient evidence, in a different case, to be lacking. "Without better evidence of when those plants [coal fired steam plants] are likely to be retired, allowing the company to increase its depreciation expenses based on what is little more than speculation about possible retirement dates would be inappropriate." Report and Order, Case No. ER-2007-0002, p. 84.

The evidence in this case relating to the estimated retirement dates for the Company's steam production plants is far better than the evidence the Commission previously found insufficient. Indeed, the estimated retirement dates in this case were developed by engineering and consulting firm Black & Veatch, through a detailed examination of numerous data sources and considerations. No party to this case has presented any serious criticism of the Black & Veatch estimates. MIEC has no criticism, and indeed their depreciation expert (who has used and continues to use the life span approach in *every single case* he has testified in for the past 25) agrees that the manner in which Black & Veatch estimated the subject retirement dates is how he would do so.[5]

The Staff leveled one very minor criticism at the Black & Veatch estimates, but admits that the Black & Veatch study is "logical" and "well done." In rejecting the quality of the Company's *evidence* two rate cases ago, but not the life span method itself, the Commission was concerned about two things; first, the lack of support for the idea that all of the Company's steam production units could be retired within a span of just 16 years; and second, that the estimated retirement dates seemed arbitrary. Report and Order, Case No. ER-2007-0002, p. 83. Neither of those two concerns remain in this case. No party claims the estimated retirement dates are arbitrary, and no party claims that Black & Veatch did not properly take into account the need to retire the plants in an orderly fashion over time, and to replace that capacity in an orderly fashion as the four plants are retired over the next 36 years -- between 2022 and 2046. Having failed to find fault with the Company's retirement date estimates (and recognizing that the mass property approach Staff stubbornly continues to use also relies upon estimates), the Staff now theorizes that its use of the mass property approach "should" lead to similar depreciation rates as does use of the life span approach. The problem with the Staff's theory is that it could only possibly be true if the database used by the Staff to develop depreciation rates by treating these steam production plants a mass property contained sufficient *final* retirement history for like plants. The Staff admits that there is very limited final retirement data available because the only final retirements that have

[5] MIEC witness Selecky does not advocate use of the mass property approach in this case. Rather, he simply calculated some depreciation rates for the Company's steam production plants using the mass property approach.

occurred were of much smaller plants, whose original cost was also far less than the investments in the current very large steam production plants operated by AmerenUE.

As outlined in detail in the direct, rebuttal and surrebuttal testimonies of AmerenUE depreciation expert John F. Wiedmayer, and in AmerenUE expert and Black & Veatch engineer Larry W. Loos' surrebuttal testimony, failure to use the life span approach will fail to properly allocate the service value of these steam production plants over their service lives Using unreasonably long average service lives for power plants will shift unrecovered investment in these plants to future customers who, when they must then pay for it after the final retirement of the plants, will not even be taking service from the then-retired plants.

a. If the life span approach is used, what are the appropriate depreciation rates?

The depreciation rates calculated by AmerenUE depreciation expert John F. Wiedmayer (with one minor exception) should be adopted.[6] The three remaining adjustments to Mr. Wiedmayer's life span depreciation rates proposed by MIEC witness Selecky (relating to the retirement date of the Meramec Plant, net salvage in Account 312, and adjustments to the life and net salvage parameters in Account 322) should be rejected.

<u>Meramec Plant Retirement Date.</u> Mr. Selecky's first adjustment arises from his arbitrary argument that Mr. Loos' retirement date estimate for the Company's Meramec Plant should be increased by five years. Mr. Selecky cites no evidence to support his argument, other than to theorize that if generating units at the other, newer and more

[6] The one minor exception relates to a minor adjustment with which the Company agrees, that is, Mr. Selecky's adjustments to the Company's proposed depreciation rates for accounts 341 to 345, Other Production, which the Company agrees lowers its production plant related depreciation expense by approximately $1.08 million from that proposed in the Company's direct case.

efficient plants last about 68-plus years, then perhaps the Meramec units will as well. As explained in detail in the rebuttal testimony of AmerenUE witness Mark C. Birk (and discussed in AmerenUE witness Wiedmayer's rebuttal testimony), Mr. Selecky's argument that the Meramec retirement date estimate should be extended by five years is overly simplistic, arbitrary, and fails to recognize the vast differences between Meramec and the Company's other steam production plants. As Mr. Birk explains, the total life of the Meramec Plant is likely to be less than that of the other newer, and more efficient AmerenUE plants. This is because Meramec's heat rate is higher (i.e., it is less efficient), the plant is older, and thus was built with earlier technology, and the plant has been operated in much more of a cycling mode, which has created more physical and thermal stress, which tends to shorten the plant's life. Mr. Selecky makes no attempt to rebut Mr. Birk's sound, reasoned support for the Black & Veatch estimate of the retirement date for Meramec. Mr. Selecky's argument to extend the Meramec retirement date is unsupported, and should be rejected.

<u>Account 312, Boiler Equipment, Net Salvage.</u> Mr. Selecky's second proposed adjustment relates to his attempt to understate a reasonable level of net salvage accruals for the Company's largest steam production account, Account 312, Boiler Equipment. In effect, he improperly relies on an examination of current or recent net salvage expense levels (relating to interim retirements at these plants that have occurred *in the past*), rather than using the retirement history data over the long history of these plants to properly accrue for future net salvage associated with these plants. This is a variant of the "expense approach" Mr. Selecky attempts to use for the Company's transmission and

distribution accounts, which the Commission has soundly rejected, and which is not used by either the Staff or the Company in this case.

As these power plants age, there are more and more interim retirements (i.e., component replacements) and has we move through time, it costs more and more to perform those retirements. This creates an ever-increasing trend in net salvage costs. That trend is apparent when one looks at the actual interim retirement (and net salvage) experience in account 312. The data shows that the three-year moving average net salvage percentages have been above (more negative) negative 30 percent for *every three-year period* since 1998. AmerenUE's depreciation expert conservatively used a net salvage percent of just negative 15 percent. As time passes that net salvage percent will need to become more, not less, negative. Mr. Selecky's proposal to make it even less negative (-10%) is unreasonable, not supported by the Company's experience, and should be rejected.

The foregoing two adjustments have a total value of approximately $13.68 million for all of the Company's steam plants. The vast majority of the $13.68 million relates solely to Mr. Selecky's arbitrary and overly simplistic argument that the retirement date for Meramec should be extended by five years (approximately $9 to $10 million relates solely to that issue). The remaining $3.8 million to $4.68 million relates to Mr. Selecky's unreasonable attempt to reduce net salvage accruals for account 312.

<u>Account 322, Reactor Equipment.</u>[7] Mr. Selecky's final proposed adjustment if the life span approach is used relates to his argument that the data for the Company's

[7] This section address issue i.c on the List of Issues "Should the retirement of the Callaway steam generators be included in the life and net salvage analysis?" The answer to that question is "yes, the retirement of the Callaway steam generators should be included in the life and net salvage analyses." Both the Company and the Staff agree.

2005 retirement of the steam generators at the Callaway Plant should be ignored because the steam generators did not last as long as originally expected and thus the retirements were in his words "extraordinary." Both the Staff and the Company disagree with Mr. Selecky's argument, and both the Staff's and the Company's depreciation rates for the Callaway Plant (including for Account 322, Reactor Equipment) are virtually the same.[8]

The steam generator replacements do not skew the life analysis for Account 322. These retirements were not extraordinary, as most nuclear power plants are or have experienced problems with their steam generators. The Callaway Plant is relatively young (having operated as of the end of 2008 for just 24 years of its currently estimated 60 year life), and over the entire expected life of the plant, the magnitude of the steam generator replacement will not be extraordinary in relation to other retirements at the plant, including large expected retirements ($48 million; the steam generator retirements costs were just $25 million) in the very near-term (the next five years), as outlined in Mr. Wiedmayer's rebuttal testimony. Indeed, had the steam generators lasted 40 years, as originally expected, it likely would have cost twice as much to remove them ($50 million, not $25 million), which means the retirement history would have contained twice as much cost of removal for the steam generators.

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[8] The Staff does use the life span approach for the Callaway Plant, but the Callaway Plant's life estimate is just as much of an estimate as the life estimates the Staff seems so reticent to use for steam production plants. Indeed, the life estimate at Callaway of 60 years is based upon a license extension that has not yet even occurred, and assumes the Callaway Plant will live two and one-half times longer than it has lived thus far. That may or may not be true, the point being that there is no reasoned basis for refusing to use the life span approach for the steam production plants, when all agree that there is nothing inherently wrong with that approach. This section address issue i.c on the List of Issues "Should the retirement of the Callaway steam generators be included in the life and net salvage analysis?" The answer to that question is "yes, the retirement of the Callaway steam generators should be included in the life and net salvage analyses." Both the Company and the Staff agree.

Mr. Selecky's life analysis for Account 322, Reactor Plant Equipment is very rudimentary. He uses one data point to determine his life estimate while Staff and the Company used 24 data points and visually fit an Iowa curve to those 24 data points. Also, Mr. Selecky simply calculates the average annual retirements, excluding the steam generators, for the first 24 years of Callaway's life. He then divides the plant exposures surviving at the plant's midpoint life (age 11.5 years) into the average annual retirement amount in order to determine a retirement ratio which he assumes is appropriate to use for every year in the plant's life from age 0 to 60. However, this shortcut life analysis method is not appropriate when actuarial analyses of mortality data are available. The life estimates, i.e., the interim survivor curve, used by Staff and the Company were based on the well-recognized and universally accepted retirement rate method of life analysis using company data related to interim retirements. Mr. Selecky did not use the retirement rate method. In addition, it is inappropriate to determine an average annual retirement amount based on the first 24 years of a plant's life and used that amount to make projections of future retirement levels as Mr. Selecky did since retirements levels are lower early on in a plant's operating life than they are later when retirement levels increase as the plant ages.. Mr. Selecky's argument is analogous to examining the retirement history (e.g., retiring an old roof and installing a new one) of a brand new home over its first 10-15 years and using that history to project retirement costs over the home's 50-75 year life. During the early years there will be little in the way of major work done on the house, but as it ages, the work (and the cost) will accelerate (new roofs, furnaces, air-conditioners, siding, driveways, etc.). Consequently, doing what we almost always do (and what both the Company and the Staff have done in this case), that is, using the retirement history in the account to develop the average service life is appropriate. Mr. Mr. Selecky's attempt to exclude this one large retirement in order to increase the life (and thus decrease depreciation expense) will likely result in an under-accrual in the account due to an overstatement of the life, and should be rejected.

Similarly, the steam generator retirements do not skew the net salvage analysis, as claimed by Mr. Selecky. The actual experienced net salvage in account 322 is -18 percent. Mr. Selecky drastically proposes to reduce it down to just -1.2 percent (even if one excludes the steam generator replacement, the actual experience would be approximately -7 percent). The Company and the Staff both use a -10 percent net salvage percent, which properly recognizes that perhaps 50% of the retirements at Callaway will be final retirements (which are accounted for in dollars collected from ratepayers and placed in the separate decommissioning trust fund required by federal law).

For these reasons, Mr. Selecky's proposed approximately $4.9 million reduction related to Account 322 should be rejected.

b. If the mass property approach is used, what are the appropriate depreciation rates?

For the reasons discussed above, the mass property approach should not be used to set depreciation rates for the steam production plants and hydroelectric units.[9] However, if the mass property approach were to be used, the Staff's proposed depreciation rates should be adopted and MIEC's proposed mass property rates should be rejected.

MIEC's mass property rates suffer from the same flaw that underlies the Staff's mass property treatment of the Company's steam production plant in Case No. ER-2007-

[9] Both the Company and the Staff use the life span approach for the Callaway Plant, and both propose the same Callaway Plant depreciation rates, which should be adopted in this case.

0002. As the Company pointed out in that case, the average service lives used by the Staff in that case (and essentially used by MIEC in this case) are grossly excessive and unreasonable. This is because MIEC treats the steam production plants as mass property, which *requires* that the entire mortality history (interim and final retirements) in the subject accounts be considered, yet MIEC ignores all steam production plant retirement history. This means MIEC's analysis assumes the steam production plants will live infinitely. For example, in the largest steam production plant account (Account 312, Boiler Equipment), MIEC uses an *average* service life of 115 years. Use of an average service life of 115 implies that one or more of the four existing coal-fired steam plants will live approximately *230 years*! – until about the year 2183 to 2206. Yet Mr. Selecky admits that he found all of the life span estimates determined by Black & Veatch to be reasonable (with one exception – he thinks 5 years needs to be added the Meramec Plant life span). Those life span estimates range from 61 to 72 years – not 230 years.

ii. What are the appropriate depreciation rates for Account 356 (Overhead Conductors and Devices)?[10]

The Company's proposed depreciation for Account 356, Overhead Conductors and Devices – Transmission, should be adopted. The Staff witness, Mr. Rice, originally proposed a 70 year average service life for this transmission plant account. He modified his life estimate to 65 years with the submission of his rebuttal testimony. The existing average service life is 55 years, which is the life estimate used by Company depreciation expert Wiedmayer.

[10] For the reasons discussed below relating to the appropriate approach for determining net salvage for the transmission and distribution accounts, MIEC's proposed transmission and distribution depreciation rates should be rejected. The below-discussion relating to Account 356 therefore applies only to whether the Staff's or the Company's Account 356 depreciation rates should be adopted.

Approximately 90 percent of the surviving investment in Account 356 was installed in the past 43 years. Transmission lines are usually constructed in conjunction with the construction of a power plant. In the past 43 years, the Company has added the following base-load power plants: Sioux, Labadie, Rush Island and Callaway. Therefore a large majority of the plant investment associated with Account 356, Overhead conductors has not yet reached an age when a significant portion of the retirements are likely to occur, i.e., 45 to 70 years. Since a large amount of the surviving investment in this account is less than 43 years old, it is important that the depreciation analyst performing the life analyses not give undue weight to the older installations that represent a much smaller portion of the total investment. This is the mistake Mr. Rice has made. Specifically, for ages from the original life table older than age 45, there is less than $10 million of investment exposed to retirement. This compares to over $137 million in total plant additions for this account. Mr. Rice's estimate only appears to be a better fit of the data because he fits the curve through age 60. As a result, he gives equal weight to data points for ages 45 through 60 as he does to earlier data points. He thus gives the older data points equal weight to the more significant data points with ages less than 45. That analysis is flawed and results in an overstatement of the average service life for this account.

iii. What approach should be used to determine the net salvage component of the depreciation rates for AmerenUE's transmission and distribution facilities and, therefore, the resultant depreciation rates for transmission and distribution facilities?

The standard approach used by the Staff and the Company, which was endorsed by the Commission in Case No. ER-99-315 and in every rate case where net salvage accruals for transmission and distribution accounts has been raised as an issue since then, should be used to set the depreciation rates for transmission and distribution plant in this case.[11] The standard approach accrues for net salvage in the manner necessary to provide for recovery of the service value of the investments in the transmission and distribution accounts over their service lives, as required by the Uniform System of Accounts. The approach used by the Staff and the Company is in accord not only with the Uniform System of Accounts (which utilities must follow, per the Commission's rules), but is also endorsed by authoritative sources, including the NARUC Depreciation Manual and the leading textbook on depreciation account, *Depreciation Systems* by Wolf and Fitch.[12] MIEC's arbitrary reduction of the net salvage that should be accrued for transmission and distribution investments is based upon the repeatedly-rejected and flawed theory that actual net salvage expense levels in the recent past (associated with plant that is no longer in service) will produce proper estimates of the net salvage expense that needs to be accrued to cover net salvage costs for the plant that is in service today, and that will be retired in the future over the coming decades. Mr. Selecky's first proposal (a $35 million offset) was completely arbitrary, and by his own admission, something he just ran "up the flagpole," and his revised offset in his surrebuttal testimony ($25 million) is equally arbitrary. Both "offsets" should be rejected.

[11] While both the Company and the Staff properly use the standard approach, a few of the parameters (the specific net salvage percents and lives) vary somewhat between the Company and the Staff. For the reasons discussed in Mr. Wiedmayer's direct testimony and as supported by his detailed deprecation study, the Company recommends that its transmission, distribution and general plant account depreciation rates, and not the Staff's rates, be adopted. The total difference between the Company's and the Staff's transmission, distribution and general account depreciation expense in this case is just $750,000. The Company's proposed expense is, in fact, $750,000 less than the Staff's.

[12] Mr. Selecky admits that Wolf and Fitch's text is authoritative on these matters, as is the NARUC Depreciation Manual.

Mr. Selecky's offsets will result in a huge ($758 million)[13] under-recovery of required net salvage expense in just the two largest transmission and distribution accounts alone. That under-recovery would have to be recovered later from future ratepayers who would not be taking service from the plant retired in the past. The under-recovery reflects service value that would not be recovered over the service lives of the assets in these accounts, a result which is at war with the fundamental goal of depreciation accounting: to recover the full service value over the service life.

Mr. Selecky's claim that the fact that the Company has accrued through depreciation rates more net salvage than it has thus far expended (over the history of these accounts) is somehow problematic is wrong and misleading. The net salvage expenses incurred in the past (e.g., over the past 50 years) are associated with a much, much smaller universe of plant placed in service decades ago when AmerenUE served about half as many customers with a much smaller system. Those expenses were also incurred in the past when the costs to remove plant that was retired were much smaller. It is no surprise that past net salvage costs do not equate to the net salvage expense that must be accrued, today and over-time, to cover the much larger universe of plant that serves much larger number of customers today. It is also no surprise that due to inflation 10-30-50 years from now, the costs to remove this plant in the future will be much higher. In fact, taking into account the universe of plant in service today, the Company should have already accrued approximately $720 million for net salvage, not the $582 million that has been accrued throughout history thus far. Thus, the Company has thus far collected *too little*, not too much. And, every dollar of the $582 million that has been

[13] The $758 million under-recovery was based upon his initial $35 million offset; the under-recovery would be smaller, but still extremely large, based on his revised $25 million offset.

collected thus far reduces the Company's rate base, which means the customers are earning a return at the utility's weighted average cost of capital (between 8 and 9 percent) on those dollars.

In summary, the standard approach properly reflects the net salvage expense associated with the plant service customers today; Mr. Selecky's approach does not.

13. Union Issues: The Unions support AmerenUE's proposed rate increase, but raise the following issues

- **i. Should AmerenUE be required to expend a substantial portion of the rate increase investing in its employee infrastructure, in general, including recruitment and training, if the Commission has the authority to require AmerenUE to do so;**
- **ii. Should AmerenUE be required to fully and permanently staff itself for its normal and sustained workload, thereby reducing the need for subcontracting and overtime, if the Commission has the authority to require AmerenUE to do so;**
- **iii. Should AmerenUE be required to repair and rebuild components and equipment internally where prudent, if the Commission has the authority to require AmerenUE to do so;**
- iv. **Should AmerenUE be required to make good faith efforts to hire first locally, then regionally and then nationally, both its internal and external workforces, if the Commission has the authority to require AmerenUE to do so?**

The Company's position on the issues raised by unions that represent some of its employees is set forth in the rebuttal testimony of AmerenUE witness David N. Wakeman. The Unions ask for relief that exceeds the Commission's legal authority. As the Commission has recognized as recently AmerenUE's last rate case[14] and on numerous other occasions, it is a body of limited jurisdiction and has no authority to

[14] *Report & Order*, Re Union Electric Company d/b/a Ameren UE, Case No. ER-2003-0318, pp. 112-13. (January 27, 2009).

take over the general management of any utility or to dictate the manner in which a utility company shall conduct its business.[15] Moreover, the Commission is not empowered to substitute its judgment for that of the directors of the utility corporation.[3] The "relief" requested by the Unions is simply beyond the Commission's authority because the Unions ask the Commission to dictate to AmerenUE who to hire and when to hire. For example, Mr. Walter asks that "the Commission demand that all jobs, internal and outsourced, be filled first within the Ameren/UE service territory, second in the State of Missouri, and third, never be offshore." (Walter, Direct, p. 8) To grant that relief, the Commission would have to dictate to AmerenUE's management who it should hire, and when that hiring should occur. This the Commission cannot do.

Mr. Walter also asks the Commission to dictate to AmerenUE's management how it should spend its revenue requirement, by asking the Commission "to require Ameren to expend a substantial portion of the rate increase on investing and re-investing in its regular employee base: hiring, training and utilizing its internal workforce to maintain its normal and sustained workload." (Walter, Direct, p. 7) To do that, the Commission would have to effectively become the financial manager of the Company. This the Commission cannot do either in that the courts have clearly held that the Commission is "not the financial manager of the utility."

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[15] *See, e.g.State ex rel.Laclede Gas Co. v. Pub. Serv. Comm 'n*, 600 S.W.2d 222, 228 (Mo. App. W.D. 1980); *State ex rel. Pub. Serv. Comm 'n v. Bonacker*, 906 S.W.2d 896, 899 (Mo. App. W.D. 1995) (*cited* by the Commission in, *e.g.*, Report and Order, In the Matter of a Proposed Regulatory Plan of Kansas City Power & Light Company, Case No. EO-2005-0329 (July 28, 2005).

14. Class Cost of Service and Rate Design:

a Low-Income Residential Customers:

i. Should the Commission establish a new customer class composed of very low-income residential customers? If so, how should it be defined?

AmerenUE has several concerns with the Commission creating a new residential class composed of very low-income residential customers. The Company believes Missouri law prohibits splitting any customer class solely to shift costs away from that class and to others. Additionally, AmerenUE believes that the problem of poverty facing some of our customers is broader than their inability to pay an electric bill. These customers have trouble paying all bills and the Company does not believe that providing electric service at a lower rate will solve any of those problems. This is a bigger issue than electric rates and it is most properly addressed at the legislature.

ii. Should the Commission approve a program to address the concerns of AmerenUE's very low-income residential customers? If so:

- **a) What should components of the program be?**
- **b) Which customers should be eligible?**
- **c) What additional conditions or limitations, if any, should be established for participation?**
- **d) How should the program be administered?**
- **e) How should the program be evaluated?**
- f) **Who should bear the program costs and how should they be recovered?**

Several utilities in the State of Missouri currently have or have had pilot programs which were designed to assist low-income customers. AmerenUE believes the best course of action would be to hold an industry workshop to discuss those programs and their results and determine what aspects worked and which need to be improved.

If the Commission desires to implement a program in this case, AmerenUE suggests a limited pilot of around a thousand customers, perhaps low income heating customers, with bill credits of $20 to $50. The costs of this pilot, or of any program ordered by the Commission, should be borne by all ratepayers and not by the Company.

b. Class Cost of Service: How should class revenue responsibility be determined?

i. If there is a new AmerenUE customer class composed of low-income residential customers, how should the change in revenue responsibility of the members of that new class be shifted to the other customer classes?

If the Commission finds it appropriate to establish a low-income program, AmerenUE believes it makes the most sense to spread the cost among all of AmerenUE's customer classes. The other residential customers are not the causers of this cost any more than are the members of AmerenUE's other customer classes. Therefore, AmerenUE recommends that any low-income program should be included in AmerenUE's revenue requirement and spread across all customer classes. (Mark, Surrebuttal, p. 5).

ii. What allocation methodology should be used for determining the production capacity allocator?

The Company's net investment in fixed production assets represents approximately 68% of net original cost rate base in this case. AmerenUE uses the 4 NCP Average and Excess method for allocating these assets, which gives proper weighting to both class peak demands and to class energy consumption (average demands). The Average and Excess method gives weight to both of these considerations by its inclusion of both average class demands and excess Non-coincident peak demands (NCP). The use of the 4 NCP demand option, rather than a lesser number of monthly NCP demands, also prevents the demand allocator for any customer class from being unduly influenced by any extreme demand in a given month. (Cooper Direct, p. 13-14)

iii. What allocation methodology should be used for determining the production fuel cost allocator?

AmerenUE classified operation labor expense, fuel and purchased power used to meet its interchange obligations as fixed, all other fuel, fuel handling, and production maintenance and operations-other expenses were classified as variable. AmerenUE's allocation of these costs in its class cost of service study is consistent with the classification and allocation of these same items in its jurisdictional cost of service study. (Warwick Rebuttal, p. 4)

iv. If the Commission relies on the Average & Peak 4 CP allocation method for determining the production cost allocator what peak demand data should it use?

AmerenUE believes that the Average & Peak 4 CP allocation method is inherently flawed as it double counts the average demand of customer classes. This double counting results from the use of class average demand for a portion of production plant allocation and the use of class peak or non-coincident peak demands, which include an average demand component for the remaining allocation of production plant. The double counting results in customers with higher load factors being allocated an inequitable share of production plant investment. (Cooper Rebuttal, p. 5).

v. What allocation methodology should be used for determining the transmission cost allocator?

The transmission system must be built to meet peak demands imposed on it. It is more reasonable to allocate transmission cost on a peak demand method rather than a method which incorporates both peak demands and average demands. (Warwick Surrebuttal, p. 3) AmerenUE uses the twelve coincident peak (12 CP) demands of each class for allocating transmission costs. Such 12 CP allocation is consistent with the development of the Ameren system transmission revenue requirement, under the MISO's Attachment O Rate Formulae in the Open Access Transmission, Energy and Operating Reserve Markets Tariff on filed at the Federal Energy Regulatory Commission. (Warwick Direct, p. 6)

vi. **What allocation methodology should be used for determining the fuel cost allocator?**

AmerenUE allocated fuel cost, with the exception of fuel for interchange sales and purchased power for interchange sales, using a variable allocator based on the megawatt-hours required at the generator to provide service to each respective customer class. (Warwick Direct, p. 10)

vii. What allocation methodology should be used to allocate net margins from off-system sales to the customer classes?

AmerenUE allocated off-system sales revenues to each class using each class' fixed production capacity allocation factor that employed the Average and Excess 4 NCP method. This allocation is consistent with Company witness Mr. Weiss' Missouri retail jurisdictional cost of service study allocation of interchange fuel and purchased power operating expenses that are related to the energy utilized for off-system sales. (Warwick Direct, p. 12)

viii. **Should the revenue responsibility of the various customer classes be based in part on the class cost-of-service study results?**

Yes. AmerenUE recognizes that factors other than cost of service are relevant to determining class revenue requirements. These factors include, but are not limited to, revenue stability, effectiveness in yielding total revenue requirements, public acceptance, and value of service. (Cooper Direct, p. 18)

ix. **Should there be an increase or decrease in the revenue responsibility of the various customer classes?**

AmerenUE is proposing to allocate the revenue increase request in this case on an equal percentage of present revenue basis that is somewhat consistent with the Commission approved non-unanimous Stipulation and Agreement Concerning Class Cost of Service and Certain Rate Design Issues in the Company's most recently completed rate case (Case No. ER-2008-0318). (Cooper Direct, p. 18).

x. If the answer to "ix" above is "yes," what basis should be used to increase or decrease the revenue responsibility of the various classes?

See item ix above.

c Rate Design:

i. **In respect to the class cost-of-service determination, including the class costof-service study determination, how should the Commission change the level of the rates of each customer class that it orders in this case?**

AmerenUE's position regarding the Class Cost of Service and appropriate design of its rates is contained in detail in the direct, rebuttal and surrebuttal testimonies of AmerenUE witnesses Wilbon L. Cooper, William M. Warwick and James R. Pozzo.

As noted above, AmerenUE is proposing to allocate the revenue increase request in this case on an equal percentage of present revenue basis. (Cooper Direct, p. 18).

In addition to the proposals discussed above, the following rate design features are being proposed by AmerenUE to restore or maintain certain uniform features of the Company's rate design that were in effect prior to Case No. ER-2008-0318.

(a) The customer charges on the SPS, LPS, and LTS rate schedules are proposed to be the same.

(b) The rates ($ per kW) for Rider B voltage credits are proposed to be the same under all applicable rate schedules.

(c) The rate ($ per billed kVar) associated with the Reactive Charge is proposed to be the same under all applicable rate schedules.

(d) The rate ($ per month) associated with the Time-of-Day meter charge is proposed to be the same under all applicable rate schedules.

For the Large General Service and Small Primary Service Rate Design, the demand and energy charges on the LGS and SPS rate schedules were increased uniformly to achieve the annual revenue requirement of these classes after uniformity adjustments described above were made.

For the Large Primary Service Rate Design, the demand and energy charges on the LPS rate schedule were increased uniformly to achieve the annual revenue requirement of this class after uniformity adjustments as described above were made. For the Large Transmission Service Rate Design, the demand and energy charges on the LTS rate schedule were increased uniformly to achieve the annual revenue requirement of this case after uniformity adjustments, as described above were made. (Cooper Direct, pp. 21-22)

ii. **At what level should the Commission set the residential class customer charge?**

AmerenUE is proposing that the residential class customer charge should be limited to $10.00 per month. (Cooper Direct, p. 21)

iii. At what levels should the Commission set the small general service class customer charge for single-phase and three-phase service, respectively?

AmerenUE is proposing that the small general class customer charge for single-phase and three-phase should be limited to $11.00 and 22.00 per month, respectively. (Cooper Direct, p. 21)

Respectfully submitted,

__*/s/ Wendy Tatro*__________

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of the foregoing was served on the following parties via electronic mail (e-mail) on this 11th day of March, 2010.

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