ATTORNEY GENERAL OF MISSOURI

JAY NIXON
ATTORNEY GENERAL

JEFFERSON CITY
65102

P.O. BOX 899
(573) 751-3321

March 6, 2007

Ms. Colleen Dale, Secretary
Missouri Public Service Commission
P.O. Box 360
Jefferson City, Missouri 65102-0360

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Missouri Public
Service Commission

Re: ER-2007-002

Dear Ms. Dale:

Enclosed for filing please find the State of Missouri's pretrial brief in the above referenced matter. The State is filing both an NP and HC version of the brief. Due to the fact that the Commission's presiding officer is requiring all parties to provide ten written copies of items filed the State will not be filing this via EFIS.

Sincerely,

JEREMIAH W. (JAY) NIXON
Attorney General

Douglas E. Micheel
Assistant Attorney General

Enclosures

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NP

MAR 0 6 2007

Missouri Public Service Commission

BEFORE THE PUBLIC SERIVCE 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-2007-0002

State of Missouri's Prehearing Brief

Pursuant to the Commission's Order approving a procedural schedule, the State of Missouri/Department of Economic Development (herein after "State") provide this prehearing brief. For brevity the State will only address issues for which it has filed testimony. The State reserves the right to take positions on any litigated issues during the hearing and in briefs at the close of the evidentiary record.

I. Introduction

This is not your typical rate case. AmerenUE is not content to compile the normal calculations of its rate base and operating income using traditional regulatory approaches. The Company's filing and positions taken in litigation are individually unique and creative, while at the same time consistent in one theme. Every new legal theory and novel ratemaking approach AmerenUE will present in this case pushes the limits of any rational view of just and reasonable rates, indicating an aggressive regulatory posture that will be revealed to the Commission as the hearings unfold.

In this case, the Company intends to test the limits of the Commission's jurisdiction over the Electric Energy, Inc., a coal fired generating unit in Joppa, Illinois, from which Missouri ratepayers have been served for many years. At the same time AmerenUE seeks to remove the low-cost Joppa base-load generation from Missouri regulation, keeping its valuable output for shareholders, the Company also seeks to move high-cost combustion turbine ("CT") generation at Pinckneyville and Kinmundy into Missouri rate base. These CTs were initially non-regulated capacity that was built by AmerenUE corporate affiliates intending to earn large profits in deregulated power markets. However, market conditions became unfavorable for gas-fired CTs, so Ameren Corporation now wants Missouri rate base inclusion to protect those investments from exposure to competition.

On the depreciation front, the Commission is asked by AmerenUE to ignore the likelihood that the Callaway nuclear plant will, like most other large nuclear generators around the country, ultimately seek and be granted an extension to its Nuclear Regulatory Commission ("NRC") operating license. By ignoring this reasonable expectation, AmerenUE seeks to increase nuclear depreciation expenses substantially. AmerenUE is also seeking large depreciation increases on the rest of its plant investment to collect inflation-adjusted future removal costs, but is not content with advance collection of only the nominal removal cost dollars from ratepayers. The Company also wants flow-through income tax accounting so that ratepayers pay income tax expense on these recoveries, which effectively costs ratepayers $1.62 for every cost of removal dollar that is advance-collected.

Energy cost recovery is another place where AmerenUE is pushing the envelope. It is not surprising that AmerenUE wants to avail itself of the opportunity to transfer the risks of its gradually increasing fuel expense to ratepayers through the recently enacted Fuel Adjustment Clause ("FAC") Rule. However, to amplify this benefit for its shareholders, this utility would prefer to understate the amount of its growing off-system sales profits and keep any differences for shareholders. AmerenUE operates a large fleet of highly efficient coal and nuclear plants that are included in Missouri rate base and that produce hundreds of millions in annual off-system sales profits. The amount of this profit that should be recognized in setting rates is hotly disputed, but one thing is clear. AmerenUE wants to keep the expected growth in its off-systems sales profits, or at least a large share of such profits under a proposed heads-they-win, tails-customers-lose "sharing" regime.

AmerenUE's FAC proposal is opposed by the Staff and by the State because it is not justified for a utility that uses very little gas or oil-fired generation, where prices are volatile. AmerenUE instead relies primarily upon coal and nuclear fuel, where prices are stable and only gradually growing. This rate case will include the latest actual known fuel prices in setting rates, and after doing so this Company's revenue requirement, as calculated by Staff and the State, is negative. This means that when all changes in the Company's revenues and costs are considered, gradually increasing fuel costs are more than paid for by customer and revenue growth, off-systems sales profits and productivity effects in the balance of the business. AmerenUE's FAC proposal represents piecemeal ratemaking, through which the Company hopes to selectively transfer the expected costs of gradually increasing fuel prices to consumers on a piecemeal basis, without accounting for revenue growth or productivity effects between rate cases.

One might expect a reasonable return on equity recommendation from a utility seeking the benefits of future piecemeal FAC regulation, retention of off-system sales profit growth, massive increases in depreciation expense, removal of Joppa capacity for the sole benefit of shareholders, subsidization of its non-regulated affiliates by selling high-cost combustion turbines to the utility at "cost", retention of all emission allowance cash flows and favorable income tax accounting, but this is not a typical rate case. AmerenUE has asked for a 12 percent ROE and then suggests that an obscure Rule 4 CSR 240-10.020 be used to add $264 million in additional revenues, only to be used to backstop any ratemaking adjustments the Commission may find reasonable. The State is confident that the Commission's careful scrutiny of AmerenUE's proposals will reveal them for what they are; unique, creative, aggressive and mostly wrong.

II. Issues to be Heard

Pinckneyville & Kinmundy: What amount should be included in rate base for AmerenUE's purchase of these CTG plants from affiliated companies?

AmerenUE purchased two combustion turbine generating stations, Pinckneyville and Kinmundy, from Ameren Energy Generating, an affiliate of AmerenUE. Regulatory approval for this transaction was initially requested at the Federal Energy Regulatory Commission ("FERC") in 2003, but the transfer ultimately took place on May 2, 2005, after FERC approval was received in Docket No. EC03-53-000 and EC03-53-001. The fair market value of the Pinckneyville and Kinmundy CTs when purchased in May 2005 should have been the price paid to the affiliated company seller, but these plants were improperly valued at their much higher net book value. (Ex. 501 Brosch direct p. 52). Pinckneyville was valued at $511per KW, while Kinmundy was valued at $416 per KW, the net book cost incurred by Ameren affiliates to build the plants. (Ex. 501 Brosch direct p. 52).

AmerenUE will argue that these transactions have already been reviewed and approved by the FERC and no further review is necessary. They will also argue that this transfer was contemplated in an earlier settlement agreement resolving a past rate case in Missouri. However, the proper valuation of these plants entering the AmerenUE rate base has not been resolved. The Missouri Commission was granted late intervention in FERC's review of the sale and submitted a letter stating that AmerenUE would be responsible for demonstrating that this transaction was prudent and reasonable in light of other options in its next rate case. (Ex. 501 Brosch direct p. 53, Schedule MLB-4). Further, AmerenUE agreed that the Commission has the full authority to analyze the prudency of this transaction. (108 FERC ¶61,081).

Public utility transactions with their corporate affiliates merit careful scrutiny because of the opportunity that exists to move costs and risks into the utility, while moving valuable assets and revenues into non-regulated affiliate entities. With this problem in mind, the Commission's rules require assets acquired by a utility from an affiliate to be priced at the lower of cost or market value. 4 CSR-15 (2)(A)(1). AmerenUE clearly violated that rule by paying a higher-than-prevailing market price for the Pinckneyville and Kinmundy assets in 2005. In response to a data request, AmerenUE provided a list of 8 comparable CT power plant sales. The prices in each transaction varied because of the unique circumstances surrounding each plant and each transaction, but the average cost per kilowatt of these 8 transactions was only $288, while the average cost per kilowatt that UE paid its affiliate for Pinckneyville and Kinmundy was $432. (Ex. 501 State Accounting Schedule B-3). Notably, each of these eight alternative transactions among non-affiliated entities was at a lower cost per KW than AmerenUE paid its affiliated company for CT capacity.

Other compelling evidence points to the excessive prices paid for this CT capacity to AmerenUE's corporate affiliate. In 2005, AmerenUE's appraiser valued a combustion turbine similar to Pinckneyville and Kinmundy at $217 per KW. (Ex. 501 Brosch direct p. 57). Further, in testimony submitted to the Commission, AmerenUE argued that two other 2005 acquisitions of combustion turbines from non-affiliates were reasonable at prices of $200 and $260 per kilowatt. (Ex. 501 Brosch direct p. 55).

Compliance with the Commission's affiliate transaction rules and basic fairness to ratepayers requires that the valuation of Pinckneyville and Kinmundy be adjusted downward to $288 per KW, the best available measure of fair market value, based upon the broad average of comparable combustion turbine sales between non-affiliated parties in years 2003 and 2005 as per the data provided by AmerenUE. The impact of this proposed adjustment on AmerenUE's requested revenue requirement can be found in State Exhibit 500 State Joint Accounting Schedules Highly Confidential Schedule B-3.

Return on Equity: What return on equity should be used in determining revenue requirement?

The State has adopted AmerenUE's proposed capital structure and almost of its capital costs. (Ex. 506 Dr. Woolridge direct pp. 9-10). Primarily relying on the discounted cash flow model ("DCF") the State recommends that AmerenUE be authorized to earn a return on equity of 9.0%.

Discounted Cash Flow

The discounted cash flow model ("DCF") is the best measure of the common equity cost rate for public utilities. Virtually all large investment firms use DCF. (Ex. 506 Woolridge direct p. 20). Under DCF, the current stock price is equal to the discounted value of all future dividends that investors expect to receive from investment in the company. (Ex. 506 Woolridge direct p. 20). The rate at which investors discount future dividends is the market's expected or required return on the common stock. Thus, that discount rate represents the cost of common equity. (Ex. 506 Woolridge direct p. 20).

Three variables and components are needed to calculate the DCF, 1) the current dividend yield, 2) the growth adjustment factor, and 3) investor's expected growth rate. With AmerenUE, the current dividend payment and stock price are directly observable. Thus, the primary issue is estimating the investors' expected growth rate. (Ex. 506 Woolridge direct pp. 23-25). Both the State and AmerenUE witness, Vander Weide, used the same group of 30 public utilities.

The inventor of DCF, Prof. Myron Gordon, calculated the dividend yield by dividing the yearly dividend by the current stock price. (Ex. 506 Woolridge direct pp. 24-25). The mean monthly dividend yield between July and December, 2006 was 4.0%. In December alone the mean dividend yield was 3.8%. Thus, to calculate the cost of common equity for AmerenUE, a dividend yield of 3.9% should be used. (Ex. 506 Woolridge direct p. 24).

The dividend yield must be adjusted. Dividends obviously fluctuate over time, and different companies announce and pay dividends at different times. When calculating DCF within a utility rate, the equity cost is multiplied to a future, yet to be achieved rate base. That results in an inflated dividend yield and growth rate. (Ex. 506 Woolridge direct p. 25). Thus, it is common for analysts to adjust the dividend yield by a fraction of the long-term expected growth rate. (Ex. 506 Woolridge direct p. 25). Therefore, dividend yield here should be adjusted upwards by half the expected growth rate over the coming year. (Ex. 506 Woolridge direct p. 26).

The growth component of DCF represents investors' expectations of the long-term dividend growth rate. Investors look at the historical and projected growth of earnings, dividends per share, and internal and book values when assessing long-term growth potential. (Ex. 506 Woolridge direct p. 26). Of those, long-term growth rates are the most important, especially when the growth is internally generated. (Ex. 506 Woolridge direct p. 27). A great deal of published information was used to calculate the investor's expectations, including *Value Line's* historical and projected growth rate estimates for earnings per share ("EPS"), dividends per share ("DPS"), and book value per share

("BVPS"). (Ex. 506 Woolridge direct p. 26). That actually represents a compilation of many more experts. The DCF growth rate indicators from the 30 similar public utilities was:

Growth Rate Data Source	Growth rate among the 30 similar public utilities.
Historic Value Line Growth in EPS, DPS and BVPS.	**2.9%**
Projected Value Line Growth in EPS, DPS, BVPS.	**4.0%**
Internal Growth ROE Retention Rate	**3.7%**
Mean/Median Projected EPS Growth from First Call, Reuters, and Zacks	**5.9% / 5.0%**

An expected growth rate of 5.0% is the most reasonable. It is closer to the higher estimates because the data show that projected growth rates were generally more than historical growth rates and more weight should be given to the projected growth rates. (Ex. 506 Woolridge direct p. 29).

AmerenUE's cost of equity is 9.0%. As stated above, the dividend yield is 3.9%, the adjustment is 1.025 and the most reasonable expected growth rate is 5.0%. With these three variables the cost of equity under DCF for AmerenUE can be calculated as follows:

Cost of Equity = (Dividend Yield) x (growth adjustment) + expected rate of growth.

AmerenUE's Equity Cost Rate	Dividend Yield	Growth adjustment	DCF Growth Rate
9.0%	3.9%	1.0250	5.0%

Source: Woolridge direct p. 30 and Exhibit_JRW-7

Reduced risk and recent tax law changes have lowered common equity cost rates.

The equity risk premium is the risk required to purchase stocks as opposed to bonds. Recently, leading academics have found the forward-looking equity risk premium to be 3-4%. (Ex. 506 Woolridge direct p. 6). Those academics argue the historical premiums are upwardly biased measures. (Ex. 506 Woolridge direct p. 6). For instance, Alan Greenspan stated that equity risk premiums have declined in recent years, due to more information available in real-time. (Ex. 506 Woolridge direct pp. 6-7). Also, the 2003 Jobs and Growth Tax Relief Reconciliation Act reduced the taxation on corporate dividends for individuals from about 30% to about 15%. That reduced the cost of equity because investors will now pay less for same return. The actual numerical reduction is debated, but could be as large as 100 basis points. (Ex. 506 Woolridge direct pp. 7-8). These facts support a conclusion that the cost of common equity has been lowered.

In this proceeding the intervener testimony on ROE ranges from 9.0% to 9.8%. The Company's ROE request is 12%. The fact that the four other ROE experts are providing recommendations within 80 base points of one another demonstrates that the Company's 12% request ROE is unreasonable on its faces and does not represent appropriate ROE for a utility such as AmerenUE.

EE, Inc.: How should the expiration of the affiliate purchased power agreements with EE, Inc. be treated for rate making purposes?

The Joppa plant is a coal-fired power plant near Joppa, IL. that was built in the 1950's to supply power for the Atomic Energy Commission ("AEC") as well as for its sponsoring utilities. AmerenUE and several other "sponsoring utilities" purchased equity interests in EE, Inc. and secured financing to construct and operate Joppa. Under long-term power supply agreements ("PSAs"), AmerenUE and the other sponsoring companies were obligated to take and pay for any excess power. (Ex. 501 Brosch direct pp. 18-19). Through the PSA sales arrangement, EE Inc. essentially shifted all of the operating risks and costs associated with the Joppa Station to its sponsoring utilities. (Ex. 501 Brosch direct p. 20).

Historically, EE, Inc. has been treated as jurisdictional by the Commission in all rate cases. (Ex. 503 Brosch rebuttal p. 9). By historically including EE Inc.'s cost-based charges as purchased power expenses in rate cases, AmerenUE ratepayers have funded EE Inc.'s operating expenses and provided a reasonable return on and return of EE Inc.'s investment in Joppa for many years. (Ex. 501 Brosch direct p. 20). This is analogous to including the 40% share in AmerenUE's rate base and operating expenses, while treating energy sales to AEC as revenue credits. (Ex. 501 Brosch direct pp. 20-21). AmerenUE even guaranteed the financing that built Joppa in 1954 and guaranteed other EE, Inc. debt in 1977. (Ex. 501 Brosch direct pp. 21-22). Further, EE Inc. continues to benefit from AmerenUE ownership through the purchasing pool that buys coal, mostly from another AmerenUE affiliate. (Ex. 501 Brosch direct p. 22).

AmerenUE for decades has used Joppa's low-cost power to serve its native load or to engage in profitable off-system sales. Until December 31, 2005, EE Inc. sold power to the sponsoring utilities at cost-based prices. (Ex. 501 Brosch direct pp. 19-20).

The issue at this time arises because AmerenUE allowed its long-standing cost-based PSA arrangement to expire, even though its 80% ownership interest and control of EE, Inc. could have continued an equitable, cost-based power supply arrangement for the benefit of AmerenUE and its ratepayers (Ex. 503 Brosch rebuttal p. 11). Immediately after the PSA was allowed to expire, EE Inc. began selling Joppa energy at much higher market-based prices and recorded sharply increased revenues and earnings on this affiliate's books. On its investment in the 40 percent ownership, AmerenUE is now realizing windfall profits, which have increased from an average historical return under the PSA of 15.1% in 2005 to 184.8% in 2006. (Ex. 501 Brosch direct pp. 25-28). The profit increase on EE, Inc.'s books occurred with no significant change in plant investment levels or operations and cannot be attributed management action allowing the windfall to be retained as a reward, but is solely a result of PSA expiration. (Ex. 501 Brosch direct pp. 27-28).

The State asserts that the market value of EE Inc.'s Joppa Plant, and its income stream, should be treated as a regulatory asset, where it will continue to benefit Missouri ratepayers. (Ex. 501 Brosch direct p. 23). Joppa's market value is the result of constructing, operating, and maintaining, largely at ratepayer risk and expense, an established asset that has appreciated in value and produces a valuable income stream. (Ex. 501 Brosch direct p. 23). The Company has conceded that it is not aware of any prior year in which EE Inc. experienced any operating losses while UE ratepayers were paying cost-based contract prices for the UE share of output from Joppa. Ex. 501 Brosch direct p. 20). Absent a showing by AmerenUE that its shareholders have borne significant risks arising from such operations outside of regulation, there is no basis to treat AmerenUE's share of EE Inc. as anything but a regulatory asset. (Ex. 501 Brosch direct p. 23).

When the cost-based contract expired, AmerenUE management shifted the market value of its share of Joppa Station from the ratepayers to its shareholders, by moving the income stream created by Joppa to its nonregulated accounts. (Ex. 501 Brosch direct p. 24). Fairness and equity dictates an outcome in which the ratepayers, who shouldered the costs and risks associated with Joppa for half a century through their rates, are not denied continuing benefit from Joppa's profitable output. (Ex. 501 Brosch direct pp. 24-25). Unless corrected by the Commission, AmerenUE will be able to extract the market value of Joppa's output for the sole benefit of its shareholders, with an unjustified increase in AmerenUE's revenue requirement. (Ex. 501 Brosch direct p. 28).

To correct the problem the Commission should impute AmerenUE's share of EE Inc.'s excessive revenue and income to AmerenUE and its ratepayers. (Ex. 501 Brosch direct p. 28). Previously, under similar circumstances of abusive affiliate relationships, this Commission (and many other commissions) has imputed revenues from affiliates arising from joint operations, such as telephone companies directory publishing affiliates, i.e. the Yellow pages. (Ex. 501 Brosch direct pp. 29-30). An appropriate method to inpute revenue is to calculate the difference between the 2005 and 2006 monthly averages to find the 'excess' profit not being achieved within EE, Inc. (Ex. 501 Brosch direct p. 28). The annualized excess profit amount, after allocating for the 40% owned by

AmerenUE and factoring up for taxes, represents a reasonable equitable imputation that, under the state's proposal that comes to about $73 million. (State Revised Schedule C-4).

Off-System Sales: How should off-system sales be recognized in AmerenUE's revenue requirement and what amount of off-system sales margin is appropriate for the test year? Should any tracking or sharing of changes in off-systems sales margins be implemented?

AmerenUE has estimated an amount of off-system sales profit margins for the test year of $183 million. (Schukar Supp. Direct, page 2). This amount results from calculation of average historical prices received by AmerenUE in making such sales over a three year period 2003 through 2005, with adjustments for certain hurricane Katrina and coal shortage circumstances that are believed to have impacted such prices. The State disputes the reasonableness of AmerenUE's proposed use of stale, 36-month average market energy prices, that are now up to four years outdated. An increasing trend in market energy prices can be observed in the Company's own pricing data. (See table at Ex. 501 Brosch Direct, page 10) To maintain consistency with test year revenue requirements that have been calculated including higher fuel prices as recent as January 2007, it is essential that current pricing also be used to quantify off-system sales, but the Company unreasonably seeks to employ its three year old average prices. More recent market energy prices are much higher, as indicated by the State's preliminary updating of energy prices using 2006 pricing data, which supported a provisional $42 million upward adjustment to the Company's proposal. (Ex. 500 State Schedule C-2, dated December 15, 2006).

More current Company-prepared data clearly indicates that the State's preliminary estimate of off-system sales profits is significantly understated. AmerenUE's own 2007 Fuel Budget shows prices and margins for off-system sales much higher than the prices and margins in the Company's off-system sales estimates. In its Fuel Budget, AmerenUE assumes that in 2007 the average market price realized on off-system sales will be ** ____** per MWH, according to the "Margin Report" provided by AmerenUE to support its 2007 Fuel Budget. That is much higher than the $35.71 average price AmerenUE proposed in its 2003-2005 averaging convention for off-system sales amounts. (Ex. 504 Brosch surrebuttal pp. 8-9). Second, according to the Company's recently approved 2007 Fuel Budget, its gross margin on off-system sales in 2007 will be ** ____** million. That is considerably above the $183 million AmerenUE is asking the Commission to include its base rates. (Ex. 504 Brosch surrebuttal p. 9).

No less than AmerenUE's budgeted 2007 off-system sales margins, as included within its own 2007 Fuel Budget, should be recognized as an appropriate amount of off-system sales margins in the revenue requirement. This amount for off-system margins should be reflective of the most recent information regarding current and expected market conditions, consistent with the basis of preparation of AmerenUE's own fuel budget. Additionally, this Company-prepared estimate should be conservative for use in this rate case proceeding for three reasons:

1) Budgeted 2007 off-system sales margins do not reflect availability of Taum Sauk. When Taum Sauk is available, significant additional off-system sales margins will be earned by AmerenUE. The negative impact upon off-system sales margins from the Taum Sauk incident was estimated to be $15 million annually in AmerenUE's response to AG/UTI-83. The impact should be larger at the higher 2007 market energy prices

2) Native loads should be higher in 2007 than in the rate case test year, due to ongoing customer and load growth. Higher native loads will reduce the amount of generation available to make off-system sales relative to the test year levels.
3) The average prices assumed in the AmerenUE internal Fuel Budget are considerably lower than the market energy prices assumed by Electric Energy Inc. in its own 2007 Budget. (Ex. 504 Brosch Surrebuttal p.10).

Fuel Adjustment Clause: Should AmerenUE's proposed fuel adjustment clause be approved and, if so, with what modifications or conditions?

Recently enacted Commission rules enable electric utilities to propose Fuel Adjustment Clause ("FAC") tracking changes in energy production costs between rate cases. These rules are permissive, but not prescriptive, and the Commission should carefully consider utility-specific facts before granting piecemeal rate changes for discrete categories of costs outside of the traditional rate making process. AmerenUE has requested a Fuel Adjustment Clause in this proceeding, but the facts and circumstances surrounding this Company's generation portfolio, fuel procurement strategies and complexities in administering any FAC argue strongly against approval of an FAC for this utility.

AmerenUE will emphasize that it has experienced significant fuel cost increases over the past several years and expects its fuel costs to continue to rise in the future. (Neff Direct, p. 5, Neff FAC Rebuttal p.10) Not surprisingly, in this environment, AmerenUE is seeking to transfer the risks of its gradually increasing fuel costs to ratepayers between rate cases. However, an FAC is only justified when traditional test year regulation cannot be expected to produce just and reasonable rates for a utility without such piecemeal rate tracking of isolated cost changes. Traditional regulation has and will continue to produce reasonable rates for this utility. The anticipated changes in AmerenUE fuel costs are not sufficiently large or volatile enough to merit special rate tracking. This utility has sufficiently hedged its exposure to fuel price volatility thru risk management and multi-year coal supply contracts. (Brosch Direct FAC, p. 20) Further, AmerenUE generates only a small portion of its energy using oil and natural gas fuel sources, and therefore does not suffer from the volatility of those markets. (Brosch Direct FAC, p. 28) Finally, unacceptable administrative complexity argues against granting an FAC for AmerenUE, because of the Taum Sauk outage, energy cost effects of EE Inc., and the expiring contract with Entergy Arkansas. (Brosch Direct FAC, pp. 29-31) In sum, AmerenUE simply has not demonstrated that its proposed FAC is needed or is consistent with the public interest.

Piecemeal Ratemaking Should Be Avoided Unless Traditional Test Year Regulation Fails

An FAC is a regulatory tool that systematically changes utility pricing between rate case test years, to track changes in fuel costs in isolation, without regard to how the utility's overall costs or revenue levels are changing between its production, transmission and generation units. (Ex. 502 Brosch FAC p. 3). In this way, an FAC is different from traditional ratemaking using test years to quantify all revenue requirement components. Traditional regulation is based upon balanced measurement of all elements of costs and revenues, not just one cost considered in isolation. (Ex. 502 Brosch FAC p. 4). Overall analysis is important because it accounts for the fact that over time favorable changes tend to offset unfavorable changes. (Ex. 502 Brosch FAC p. 4). The primary problem with an FAC is the potential for serious distortion of the "matching" that is desirable in rate case test years. (Ex. 502 Brosch FAC p. 9). The matching principle recognizes the importance of matching all revenues and costs in a consistent time period to determine if changes are needed in utility rates. (Ex. 502 Brosch FAC p. 9). An FAC is piecemeal rate-making, ratepayers are only charged for pieces of the overall revenue requirement without regard to whether changes to other expenses or increasing sales levels mitigate the fuel cost changes. (Ex. 502 Brosch FAC p. 9). All elements of the revenue requirement change over time and favorable changes tend to offset the unfavorable changes. But if AmerenUE can select certain items for special treatment, one can reasonably expect the selected items will be "cherry-picked" so to influence the regulatory process. (Ex. 502 Brosch FAC p. 9).

Incentives for Management Efficiency are Blunted by FAC Regulation

The second problem with the piecemeal regulation resulting from use of an FAC is the elimination of incentives to reduce fuel and purchased power costs. (Ex. 502 Brosch FAC p. 10). Traditional test period rate-making creates incentives for management to control and reduce costs to earn at or above authorized return levels. (Ex. 502 Brosch FAC p.5). Once utility rates are set in a rate case test year, any favorable changes such as cost reductions and sales margin growth work to produce returns over what the Commission authorized, providing management with a regulatory lag incentive to control costs. Through this process, regulatory "lag" causes management to be rewarded for controlling costs and penalized for not controlling costs between rate cases. (Ex. 502 Brosch FAC p. 10). If an FAC is used, any incentive to control FAC-recoverable fuel costs is virtually eliminated. (Ex. 502 Brosch FAC p.11). In an FAC cost "pass through" environment regulatory auditing becomes critically important to review FAC cost recoveries, but such auditing is no substitute for ever-present incentives. (Ex. 502 Brosch FAC p. 13).

Consider the fact that AmerenUE presently incurs significant capital and O&M expenses in an effort to maximize the availability and efficiency of its power plants. (Ex. 502 Brosch FAC p. 11). Under traditional regulation, balanced incentives exist for management to optimize power plant investment and maintenance costs because non-fuel costs of this type are treated the same way as avoided fuel costs by regulators. (Ex. 502 Brosch FAC pp. 11-12). This balanced regulatory incentive is destroyed by introduction of an FAC. Entirely rational management behavior with an FAC in place would be to subtly reduce spending on production maintenance charges and de-emphasize capital projects aimed at improved generating unit availability or heat rates, because any corresponding reductions in energy costs simply flow through the FAC to ratepayers. (Ex. 502 Brosch FAC p. 13).

AmerenUE has acknowledged an FAC's detrimental effect on incentives. In 1998, its then-CEO Charles Mueller stated, "The fact we have operated for years without a fuel adjustment in Missouri has given us additional incentive to continue to manage fuel costs effectively." (Ex. 502 Brosch FAC p. 12 citing AmerenUE's 1998 Annual Report).

Regulatory Complexity and Risk Shifting Argue Against an FAC for AmerenUE

The third problem with an FAC is that it increases the financial burden on ratepayers. First, it shifts all risk of fuel and purchased energy costs from the utility to its ratepayers who are the least able to influence such costs levels. (Ex. 502 Brosch FAC p. 14). Unless regulators allow an adjustment to authorized rates of return to account for that shift, there is no benefit to ratepayers from implementation of an FAC. (Ex. 502 Brosch FAC p. 14). Moreover, an FAC produces less predictable energy costs and more complex billing to ratepayers. (Ex. 502 Brosch FAC p. 15). Further, an FAC creates administrative complexity and increased costs associated with audit verification and administration of complex accounting entities, cost allocations and related tariff calculations. (Ex. 502 Brosch FAC p. 15). AmerenUE even admitted that the FAC would create extensive minimum filing requirements and exhaustive monthly survey data. (Ex. 502 Brosch FAC p. 15).

Generally, an FAC should only be allowed in compelling or extraordinary circumstances when the types of costs to be tracked on a piecemeal basis have the following attributes:

1) Costs are large enough to have a material impact on revenue requirements and the utility's financial performance, if not tracked;

2) Costs that are beyond the control of management, such that regulatory lag incentives are ineffective;

3) Costs that are volatile enough to cause significant swings in income and cash flows, if not tracked;

4) Cost tracking tariffs should be straightforward and simple to administer; and

5) Tracking of costs must be balanced and not distortive of test period relationships. (Ex. 502 Brosch FAC pp. 8, 15 & 16).

AmerenUE's Proposed FAC

AmerenUE has proposed a very inclusive FAC that does not meet the aforementioned criteria for exceptional rate tracking procedures. Under the Company's proposal, the Commission would set a base level of all fuel and purchased power costs in this case. Then future variations from the base rate recovery level would be deferred during rolling three month accumulation periods, for translation into FAC rate changes 3 months after the conclusion of each accumulation period. (Ex. 502 Brosch FAC pp. 17-18). As noted above, AmerenUE engages in significant off-system sales of the energy it produces. AmerenUE's primary proposal for addressing off-system sales margins is to include a fixed amount of off-system sales margins in the revenue requirement and not track changes in off-system sales margins within the proposed FAC. (Ex. 502 Brosch FAC p. 18). As an alternative recommendation, AmerenUE would like to implement a sharing proposal within the FAC, where off-system sales margins could be partially retained for the Company's shareholders, even though the cost of generating resources that make such sales possible are borne entirely by ratepayers and shareholders bear none of the costs and risks associated with such generating facilities. (Ex. 501 Brosch Direct, p. 14).

As explained below, AmerenUE's circumstances do not justify exceptional piecemeal ratemaking in the form of an FAC tracker for changes in its fuel and purchased power expenses. (Ex. 502 Brosch FAC p. 18). AmerenUE does not face the volatility and lack of control over fuel faced by other utilities, allowing AmerenUE to reasonably recover its fuel costs through base rates, as it has done for many years prior. (Ex. 502 Brosch FAC p. 14 citing McShane direct p. 9). Generally, only very large and volatile utility costs, where cost changes are beyond the control management and that are substantial enough to cause potential earnings volatility, if not tracked, are eligible for consideration for piecemeal rate tracking treatment. But AmerenUE's fuel, fuel-transportation, and purchased power costs are less volatile and more controlled by management than at other utilities. The lack of volatility and amount of control is illustrated by looking at each of AmerenUE's energy costs: 1) coal; 2) purchased power; 3) nuclear; and 4) oil and gas.

AmerenUE's coal costs are stable and make up most of its fuel costs

Coal price volatility is very important to AmerenUE's FAC request because 79% of AmerenUE's electricity is from coal-fired power plants. (Ex. 502 Brosch FAC p. 20). AmerenUE employs a coal price hedging strategy with the primary goal of protecting against the volatility of coal prices and a secondary goal of lowering prices. (Ex. 502 Brosch FAC p.21). AmerenUE ** _____ ** (Ex. 502 Brosch FAC pp. 20-21).

While AmerenUE emphasized in its testimony that coal prices have increased in the past few years, these historical price increases will be completely captured in the true up calculations for this rate case, making only future prices relevant. (Ex. 502 Brosch FAC p. 21). AmerenUE's future price of Coal is not expected to materially increase. Coal industry publications do not predict continuation of the increases and note several reasons for flat prices in the future. (Ex. 502 Brosch FAC p. 22). Lastly, it is reasonably expected that the true-up of AmerenUE fuel prices will show a downward adjustment in coal costs. (Ex. 502 Brosch FAC p. 22, Ex. 500 State Accounting Schedule C-3, line 1).

Rail freight costs make up a large percentage of overall delivered coal costs, and have experienced large price increases historically, that are effective January 1, 2007. (Ex. 502 Brosch FAC p. 22). But, as with coal prices, the past expenses and January 1, 2007 increase are fully includable in true-up expense calculations for this rate case. Future rail freight prices after 2007 will not be volatile because AmerenUE has ** ___.** (Ex. 502 Brosch FAC p. 23). Also, for freight costs not covered under the ** ____,** the predicted increases are not material. Based upon existing fixed price contracts for rail freight, the predicted overall increase is only ** ___ ** per ton, which represents less than 1% of AmerenUE's annual Missouri retail revenue. (Ex. 502 Brosch FAC p. 24).

Purchased power costs will be offset because AmerenUE is a net seller of purchased power

Purchased power costs represent the source for about 14% of AmerenUE's test year kilowatt hours, and also do not represent a cost exposure that merits FAC tracking. (Ex. 502 Brosch FAC p. 25). A significant portion of recorded purchased power expense relates to MISO, charges for transmission line losses which should remain stable in the future. (Ex. 502 Brosch FAC p. 25). Most of AmerenUE's remaining purchased power expense is associated with a cost-based power supply contract with Entergy Arkansas. (Ex. 502 Brosch FAC pp. 25-26). Once that contract expires in 2009, AmerenUE will be exposed to market prices for purchased power. Notably, AmerenUE's contract with Entergy Arkansas is a good example of the complexity and inequity that can arise from an FAC. When this power supply contract expires, AmerenUE will recognize a capacity charge savings of *** ___ *** million, an amount within its current base rate. (Ex. 502 Brosch FAC p. 26-27). With an FAC in place, ratepayers will pay for the replacement energy through the FAC, while the shareholders get to keep the substantial capacity charge savings that are not proposed to be "tracked" through the proposed FAC. (Ex. 502 Brosch FAC pp. 26-27). Overall, AmerenUE is a net seller of energy since it sells more off-system energy than it buys, such that the Company should profit from any higher market energy prices in the future. (Ex. 502 Brosch FAC p. 26)

Nuclear Fuel prices do not create volatility or significant financial exposure.

The Callaway Nuclear plant generates the next largest component part of test year energy, representing about 7% of AmerenUE's energy supply costs. There are three components of the Company's Nuclear fuel costs: fuel expenses, spent fuel costs, and nuclear decommissioning and dismantling charges. (Ex. 502 Brosch FAC p. 27). The last two components have a fixed per year cost: for spent fuel and the decommissioning and dismantling charges. (Ex. 502 Brosch FAC p. 27). The first and largest component, the cost of nuclear fuel, has experienced stable prices that are expected to remain stable.

Nuclear fuel costs are subject to change only at the time of each refueling outage for Callaway and the prices reflected in the Company's test year fuel run reflect prices effective with the spring 2007 refueling outage cost levels. (Ex. 502 Brosch FAC p. 27). Thus, there is no significant volatility or cost exposure associated with nuclear costs that merit FAC rate treatment. (Ex. 502 Brosch FAC p. 27).

AmerenUE uses very little oil and natural gas, thus it has no material financial exposure

While there is significant volatility in fuel oil and natural gas market prices, AmerenUE has little exposure because it uses very little of these fuels. AmerenUE relies on oil and natural gas fired units for less than ** ___ ** percent of annual generation. (Ex. 502 Brosch FAC p. 28 citing Finnell workpaper FBREPORT_PSCO5_Sep8.xls). Further, oil and natural gas makes up only about 3% of AmerenUE's total energy supply costs. Additionally, AmerenUE expects to run its oil and natural gas fleet only a small percentage of the time over the next few years. (Ex. 502 Brosch FAC p.20). Thus, AmerenUE does not have the significant financial exposure to oil and natural gas price volatility that is needed to justify an FAC.

Administrative Complexity concerns

Any FAC granted for AmerenUE will prove to be particularly difficult to administer, audit and verify. If an FAC is approved, comprehensive monthly financial and operational data will need to be filed then reviewed analyzed, and/or audited by the Commission's Staff. (Ex. 502 Brosch FAC p. 29). Additionally, surveillance monitoring reports are required and become much more important because they enable the Staff to track whether the FAC's piecemeal rate changes are contributing to excess earnings. (Ex. 502 Brosch FAC pp. 29-30). Further, additional, detailed quarterly reporting of rate change calculations would also be filed. (Ex. 502 Brosch FAC p. 30). Lastly, AmerenUE has recommended that the Staff review all of that within 30 days, and this process does not include the 18-month prudence reviews that are required.

Regulating an FAC for this utility becomes even more complex due to Taum Sauk outage and the EE, Inc. issue (Ex. 502 Brosch FAC p. 31). As discussed above, the Taum Sauk incident will cause higher fuel and purchased power costs to be incurred. Those costs are not to be passed through to ratepayers because the Commission's FAC rules preclude recovery of increased costs resulting from negligent or wrongful acts or omissions by the utility. Thus, any AmerenUE FAC would require careful monitoring and ongoing special studies to ensure that ratepayers are not charged Taum Sauk outage effects. (Ex. 502 Brosch FAC p. 31). Expiration of the EE, Inc. purchased power contract will also cause AmerenUE per books fuel and purchased energy expenses to be much higher than if the purchased power agreement with EE Inc. had been continued. (Ex. 502 Brosch FAC pp.31-32). Accounting for Taum Sauk and EE Inc. adjustments will add considerable complexity to any FAC administration procedures.

Consideration of regulatory complexities and administrative burdens, when combined with AmerenUE's absence of any compelling financial need for an FAC, argues for rejection of the Company's proposal.

Depreciation: 4 CSR 240-10.020: Does 4 CSR 240-10.020 require any adjustment in this case for return on depreciation reserve? If so, what adjustment does 4 CSR 240-10.020 require?

AmerenUE has argued that 4 CSR 240-10.020 allows it to increase its rate request by an additional $264 million and provides additional support for the Company's asserted revenue requirement, effectively canceling out any downward adjustments the Commission might order up to this amount. (Ex. 503 Brosch rebuttal p. 3). If true, the Company's interpretation of this rule would significantly increase the revenue requirement by offsetting downward adjustments proposed by other parties and rendering moot Commission decisions intending to approve such adjustments in this case. (Ex. 502 Brosch rebuttal p. 3).

In reality the referenced regulation does nothing of the sort; the Rule actually appears to provide for an accounting of presumed amounts of income on depreciation reserve accounts. (Ex. 503 Brosch rebuttal pp. 4-5). AmerenUE's unreasonable interpretation of this Rule would charge ratepayers an 8.876% rate of return on $4.5 billion in depreciation reserves while allowing a return credit to ratepayers of only 3% on the same reserves. (Ex. 503 Brosch rebuttal p. 4). That would require accounting for depreciation reserves at two different rates of return, a credit at 3% and a charge to ratepayers at 8.876%. (Ex. 503 Brosch rebuttal p. 6). AmerenUE's interpretation just does not make any sense; it would charge ratepayers a net return on investment balances that have already been returned to investors via depreciation recoveries in prior years. (Ex. 503 Brosch rebuttal p. 7). There is no economic justification for including any capital costs within revenue requirements for the depreciation reserve balance, that by definition ratepayers have already returned to AmerenUE. (Ex. 503 Brosch rebuttal p. 7). Finally, this Commission has never applied 4 CSR 240-10.020 in the manner suggested by AmerenUE.

A more logical application of 4 CSR 240-10.020 would be to impute income for depreciation reserves at 3 percent and do nothing else. But, that approach would lower AmerenUE's revenue requirement by $134,861,000. While such a direct reduction of costs was apparently intended under this rule, the result would tend to understate the Company's actual cost of service, thus it is not recommended by the State.

Should the Commission assume that the Callaway Plant will be relicensed for an additional 20 year term, or should the Commission assume that the Callaway Plant will not be relicensed for purposes of calculating depreciation rates for the Callaway Plant?

The Callaway plant's existing Nuclear Regulatory Commission ("NRC") license has a term of 40 years starting in 1984. Thus in the test year, 2006, Callaway has 18 years remaining on the existing license. (Brosch Direct, p.44) However, like other currently operating nuclear plants, Callaway's operating license will most likely be extended an additional 20 years beyond its current expiration dates. (Brosch Direct, p.44, Schedule MLB-3) Therefore, the increased depreciation accrual rates being proposed by AmerenUE for the plant, that assume no license extension for the Plant, should be rejected.

Two considerations make Callaway relicensing likely. First the plant most similar to it, Wolf Creek, has already applied for license extension and regulators in Missouri and

Kansas have recognized a longer remaining life for that plant. Second, major investments have been made by AmerenUE to ensure that equipment at the plant and recent upgrades support the opportunity to seek license extension. While, there is no certainty regarding an application or NRC approval of a Callaway operating license extension, available information suggest that license extension is more likely than not, for purposes of ratemaking decisions at this time.

The nuclear unit most comparable to Callaway is Wolf Creek. Wolf Creek has already applied for an operating license extension. (Ex. 501 Brosch direct p. 44). Callaway and Wolf Creek have the same design for the plant component known as the power block. (Ex. 501 Brosch direct p. 48 citing Data Request AG/UTI-185). Notably, Wolf Creek's owner already reduced its annual depreciation accruals as well as its decommissioning accruals for Missouri ratemaking purposes, as a result of anticipated re-licensing of that plant. (Ex. 501 Brosch direct p. 49). Further, the Wolf Creek utility's Missouri rates already reflect the economic benefits of the expected approval of an NRC license extension, if accepted by the Commission.

AmerenUE's upgrades of Callaway's equipment make relicensing likely

AmerenUE has made extensive recent investments at Callaway that make re-licensing more likely to be approved. Examples of such investments include the steam generator replacement and turbine upgrade projects. (Ex. 501 Brosch direct p. 46). AmerenUE has identified a listing of monitoring activities and test used to track component life at Callaway and the expenses for this activity have been significant historically are area expected to grow in the future. These investments and monitoring costs are sought for recovery by AmerenUE in its revenue requirements. (Ex. 501 Brosch direct p.46, 50). According to AmerenUE, the single most critical consideration in determining whether or not relicensing may be feasible is the condition of the reactor vessel. According to AmerenUE, extensive monitoring is in place at Callaway to measure neutron embrittlement of the vessel wall and current shelf-life energies equate to a vessel life of greater than 80 years. (Ex. 501 Brosch direct p. 48 citing Data Response AG/UTI-189).

Callaway Depreciation Accruals Should Not Be Increased

The currently effective Callaway depreciation rate is 2.6% for all nuclear plant accounts. (GSW-WP-E1335). In the current case AmerenUE is seeking approval for a depreciation accrual rate for Callaway of 3.44%, based upon the unreasonable assumption that no re-licensing will ever be secured for Callaway. (Ex. 501 Brosch direct pp. 45-46). The additional depreciation expense associated with this proposal is an increase of $22.9 million. (Ex. 501 Brosch direct p. 45-46). Given the reasonable expectation that an operating license extension will ultimately be requested and approved for Callaway, the existing Commission approved depreciation-accrual rates should not be changed until a re-licensing decision is made and the associated known and measurable retirement date becomes known. In the alternative, if the commission determines it appropriate to revise the Callaway depreciation accrual rates at this time, care should be taken to account for the reasonable expectation that NRC license extension will be requested and granted, as an offset to upward pressure on nuclear depreciation accruals caused by interim additions. (Ex. 501 Brosch direct p. 47).

Income Taxes: Should net salvage (cost of removal) be normalized?

Cost of Removal ("COR"), also referred to as "net salvage", represents the expenditures made by a utility to remove, dismantle and retire utility plant assets at the end of their useful lives. COR is accrued on the books throughout the useful life of the utility plant asset, as part of the prescribed depreciation accrual rats that are also used to quantify depreciation expense for ratemaking purposes, so that ratepayers are charged COR as part of test year depreciation expense. (Ex. 509 Brosch Supplemental Surrebuttal, p. 4) However, these accrual basis COR amounts are not immediately deductible in calculating taxable income and income tax expenses. Instead, what is deductible for income taxes is actual, current year COR expenditures made upon asset retirement. This difference in the timing of book accounting for a cost versus the timing of tax deductibility creates a temporary "book/tax timing difference" that can be afforded one of two possible accounting treatments; 1) flow through accounting for income tax expenses on a cash basis; or, 2 normalization of the timing difference by provision of deferred income taxes. (Ex. 509 Brosch Supplemental Surrebuttal, p. 5,6)

AmerenUE witness Mannix proposes to use a "flow through" tax accounting method for accrued for accrued and incurred Cost of Removal, using corrected COR amounts to increase income tax expense by $14.9 million and revenue requirement by $24.1 million. (Surrebuttal Testimony of Charles Mannix, p.4) Staff witness Rackers proposes, in the alternative, to correct Staff's income tax expense calculation for the same item, but to adopt "normalization" accounting, rather than flow-through, which would reduce Staff's revenue requirement by about $35 million (when combined with other changes). (Surrebuttal Testimony of Steve Rackers, p. 5) The combined impact of these two late-filed revisions by Messrs. Mannix and Rackers is to broaden the revenue requirement difference between Staff and the Company by about $59 million. At the heart of this issue is whether "flow-through" versus "normalization" accounting should be applied to the book/tax timing difference that arises from COR accruals and expenditures.

State witness Mr. Michael Brosch illustrated the difference between flow-through versus normalization accounting in his Surrebuttal Schedule MLB-13. This Schedule shows that normalization accounting provides for a levelized income tax expense and constant effective tax rate, by providing deferred income taxes on the COR accruals that are not deductible until the end of the life of an illustrative plant asset. In contrast, flow-through accounting produces higher income tax expenses in every year of the asset's life except the last year, when all of the COR is incurred and deducted, at which time income tax is a negative expense value. This illustration shows the importance of practicing normalization accounting for COR, as the only reasonable way to provide any assurance that ratepayers will actually receive the income tax deduction they are entitled to after paying the COR amounts embedded within rate case depreciation expense. (Ex. 509 Brosch Surrebuttal Surrebuttal, p.8)

Under the Company's proposed flow-through approach, a different and much lower COR deduction is used in calculating test year income taxes than is being collected from customers. This is highly problematic, because the ratemaking tax deduction for COR would only rarely include actual COR for the retirement of life-span depreciated power generating stations and even if a distant future test year did include a large power plant retirement with a correspondingly large lump-sum COR tax deduction, it would be highly unlikely for the Company to proposed and the commission to set rates based on the resulting negative income tax expense in that year. (Ex. 509 Brosch Supplemental Surrebuttal, p.9)

The large revenue requirement difference arising from the flow-through versus normalization accounting for COR timing differences is explained by Mr. Brosch as arising because, under flow through accounting, each additional dollar of accrual-basis COR that is recognized for ratemaking purposes as a component of approved depreciation accrual rates, in excess of the current year actual COR expenditures, will add $1.62 into revenue requirements, making advance collection of COR within book accrual rates highly uneconomical for customers. (Ex. 509 Brosch Supplemental Surrebuttal, p.10) Normalization accounting, in contrast, would require the Company to set aside some of the cash flow collected for COR to pay the income taxes on the book/tax timing difference and to record deferred income tax expenses. These deferred income tax provisions would reverse in the future, whenever the corresponding cash expenditures are made upon retirement of utility assets. (Ex. 509 Brosch Supplemental Surrebuttal, p.11)

Normalization accounting for book/tax timing differences is practiced by AmerenUE for most other book/tax timing difference items and the normalization method is consistent with Generally Accepted Accounting Principles ("GAAP") and with the Uniform System of Accounts that is prescribed by FERC. (Ex. 509 Brosch Supplemental Surrebuttal, p.11-13) Any authority relied upon by the Company in the past to flow-through COR income taxes is unclear, but the State recommends that any ambiguity regarding past flow through be remedied in this case, by a clear prescription of normalization accounting by the Commission. The Commission should reject the flawed flow-through accounting method for COR, so that the much larger amounts of COR now proposed for inclusion in book depreciation accrual rates are normalized to produce levelized effective income tax rates and to provide some assurance that the corresponding tax deductions for COR in the future will be recognized in setting rates, as a matter of equity to ratepayers. (Brosch Supplemental Surrebuttal, p.14)

Should revenues received from environmental allowances (SO2 transactions) be included in the revenue requirement and if so, what amount?

In calculating its revenue requirement in this case AmerenUE has included $3.9 million of income arising from gains realized by the Company from the sale of SO2 emission allowances. (Ex. 501 Brosch Direct p. 37). The State believes this amount grossly underestimates AmerenUE's historic and ongoing level of emission allowance sales gains and is recommending a more representative four year average of actual emission allowance sales that have been made by AmerenUE in years 2003 through

2006. The State recommends embedding an amount of SO2 emission allowances of $20.3 million in the revenue requirement calculation, with deferral accounting for any future departures from this amount. (Ex. 500 State Accounting Schedule C-8).

AmerenUE has a surplus of SO2 emission allowances currently worth **___** million. (Brosch direct p. 38). Ameren created that emission allowance surplus primarily by purchasing low-sulfur coal. But low-sulfur coal costs more than ordinary coal, due to the smaller amount of pollution it generates. (Ex. 501 Brosch direct pp. 38-39). Thus, AmerenUE created its emission allowance surplus through higher fuel costs that were borne entirely by its ratepayers. (Ex. 501 Brosch direct pp. 38-39). Therefore, ratepayers created the surplus by paying for the low-sulfur coal such that all profits from selling the emission allowances should be credited to the ratepayers. (Ex. 501 Brosch direct pp. 38-39).

A four year average of sales should be used to calculate the allowance sales credit to ratepayers. (Ex. 504 Brosch surrebuttal p. 15). Then, a regulatory asset or liability would be recorded each month reflecting the amount that the retail portion of actual allowance sales varied from the average. (Ex. 504 Brosch surrebuttal p. 15). Under this approach AmerenUE would be made whole for any differences between the ratemaking level of sales and future actual allowance sales levels. (Ex. 504 Brosch surrebuttal p. 16). It would also account for variations above and below the dollar amount recognized in setting the rate. (Ex. 504 Brosch surrebuttal p. 16).

AmerenUE's counter-argument of retaining allowance sales proceeds for possible funding of upcoming substantial environmental investments is entirely speculative.

AmerenUE has made no showing regarding its future revenue requirements, or how such amounts would be impacted by its proposed denial of ratepayer participation in emission allowance sales. (Ex. 504 Brosch surrebuttal p. 16). Further, its proposal to defer all allowance sales proceeds and to reflect no emission allowance sales in setting the revenue requirement should be rejected for numerous reasons. First, AmerenUE has a history of significant emission allowance sales that are clearly utility-related and for which ratepayers have an undisputed claim to participate. (Ex. 504 Brosch surrebuttal p.17). Second, ratepayers will bear significant ongoing costs as part of AmerenUE's SO2 coal price adjustments and the allowance sales should be recognized as offsets of these current period costs. (Ex. 504 Brosch surrebuttal p.17). Lastly, if the Commission approves the fuel adjustment clause, it would be appropriate to also track changes to emission allowance costs and revenues relative to levels included in the base rates. (Ex. 504 Brosch direct pp. 39-40). That would achieve a balanced regulatory treatment of complementary resources used by AmerenUE in the conduct of its business. (Ex. 504 Brosch direct p. 40).

Respectfully submitted,

JEREMIAH W. (JAY) NIXON
Attorney General

DOUGLAS E. MICHEEL
Assistant Attorney General
Missouri Bar No. 38371

ROBERT E. CARLSON
Assistant Attorney General
Missouri Bar No. 54602

Attorneys for the State of Missouri
P. O. Box 899
Jefferson City, Missouri 65102
(573) 751-3338 Telephone
(573) 751-2041 Facsimile
douglas.micheel@ago.mo.gov
bob.carlson@ago.mo.gov

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and accurate copy of the foregoing was served upon all parties on this 06th day of March 2007.

Douglas E. Micheel